MODERN STEAM GENERATING EQUIPMENT

Design
Application
Operation

COMBUSTION ENGINEERING, Inc.
WINDSOR, CONNECTICUT

MODERN STEAM GENERATING EQUIPMENT

DESIGN, APPLICATION, OPERATION

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Prepared by E. A. Ferris of the Industrial Relations Department to provide young engineering employees with a synopsis of recent developments and present practices in steam generation.

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MODERN STEAM GENERATING EQUIPMENT

DESIGN, APPLICATION, OPERATION

The design of equipment for the combustion of fuels and the generation of steam is by no means an exact science. While theoretical analysis and the application of gas flow and heat transfer data, experimentally determined, are essential in establishing design standards, actual practice leans heavily on experience. It is next to impossible to reproduce field conditions in a laboratory, and often difficult to apply laboratory data to anticipated practice. Limits which are applied today may be discarded tomorrow as developments in materials, fuel production methods, or other related factors progress.

The following discussion offers a general cross section of present practices. An attempt has been made to arrange the subject matter in orderly sequence, but the interrelation of the various factors is such that this is not always possible. Generally, the sequence follows the flow of fuel and air into the furnace and the products of combustion thru the unit.

INTRODUCTION

EQUIPMENT SELECTION

In the design of any mechanical equipment, reliable operation is of primary importance. The selection of steam generating equipment should be such as to provide steam cost consistent with this reliability. Variations in fuel supply, load factors, site conditions, building costs and operating costs complicate this problem to the point where almost every large installation is tailor-made.

For example, it is possible that more expensive fuel burning equipment may permit the use of a less expensive fuel, the addition of secondary heat absorbing equipment will increase operating efficiency, or an increase in furnace size (and probably also building size) may reduce operating difficulties, maintenance, and hence, labor costs. In every case an effort is made by those responsible for the design and application of the equipment to evaluate the costs of fuel, maintenance, operating labor, auxiliary power, and capital expenditure to obtain the lowest overall steam cost. Naturally a plant with a high load factor (such as one which is to be base-loaded) can afford higher capital expenditures to obtain higher efficiency than a similar installation with a low load factor, or one which will be operated intermittently, a hydro-electric standby, for instance.

These examples suggest some of the reasons for the rather wide difference in types of equipment and their application. In general, the component parts are to some extent standardized, but there is a wide variation in the arrangement and location of heat-absorbing surfaces.

Following are some of the factors which should be considered in the selection of steam generating equipment:

FACTS
Equipment cost
Building cost
Fuel supply price survey
Auxiliary power cost

PREDICTIONS
Fuel savings: higher efficiency
Fuel savings: lower cost fuel
Fuel savings: reduction in standby losses
Load factor
Operating labor cost
Maintenance cost
Marketability of ash

JUDGMENT
Reliability
Ability to maintain high efficiency
Ability to burn coal, oil, gas, hence
Bargaining advantage in fuel purchases
Slagging
Control of fire conditions, particularly during rapid load changes
Attitude of operators toward new equipment
Stack emission

• • •

In practice, power generating units have become quite large - 250 to 350 megawatts being fairly common. Power generating systems are growing at an exponential rate. Labor and fuel costs have greatly increased in recent years. Since construction and operating labor costs do not increase directly with unit size, labor and fuel costs suggest, and system sizes often permit, very large and highly efficient - altho costly - steam generating units and prime movers. Thus, in the combination of capital, operating labor, fuel, and maintenance costs which represent the cost of a kilowatt hour at the bus, a higher capital cost permits a lower total. (Roughly, the breakdown of power generating cost in a modern electric power plant is about forty per cent fuel, forty per cent capital costs, and twenty per cent labor and maintenance.) These considerations also apply to large industrial units.

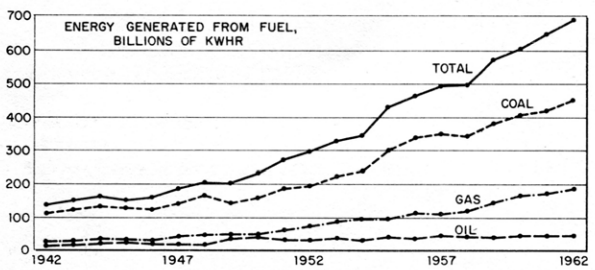
The current trend in small industrial units, however, is toward standardized designs of package boilers, often arranged for automatic operation burning oil or gas. Erection, refractory, and installation costs being considered, such shop assembled units are often more competitive in the overall aspects than units individually designed for given plant conditions. In such cases, too, a higher priced fuel may more than offset the higher operating cost with coal.

FUELS AND FIRING

FUELS

The substances which are available in this country in such quantity and quality as to be considered as commercial fuels are coal (including lignite), coke (which is made from coal), oil, natural gas, and in some localities, wood. There are many other materials which have some value as fuel but are not sufficiently common to be so designated; often their use is dictated by the need for disposal or for obtaining by-products. Sawdust, bark, sewage sludge, bagasse, blast furnace gas, refinery and coke-oven gas, petroleum coke, black liquor from the preparation of paper pulp might be so classified.

Many methods of burning fuels have been developed in an attempt to provide reliable operation at minimum cost. Refuse fuels do not usually justify large capital expenditures for increased operating efficiency, since the reduction in the amount of fuel burned would not off-set the interest on the additional investment. Where they supplant purchased fuels however, (i.e., no excess refuse) care in their efficient utilization is fully justified.



With hand firing and stoker firing of solid fuels, little or no preparation of the fuel is required at the plant. Sometimes, however, crushers are provided. Some of the midwestern coals require "tempering" (the addition of some moisture) when they are to be burned on chain or bar grate stokers.

Practically all coal is partly cleaned (part of the mineral matter removed) at the mine to improve the burning characteristics and reduce transportation cost. Most coal is crushed and screened, and sold in size groups, such as lump, nut or slack. Anthracite, the importance of which as a commercial fuel is diminishing, has always been screened to close limits. Bituminous coal size groups cannot be as closely maintained as anthracite, because the coals are more friable and break up in handling and transit. Lignite contains considerable inherent moisture and a lesser amount of surface moisture to a total of about one-third its weight. Coke "breeze" consisting of dust and small pieces which break off in bulk handling of coke is used as a steam fuel. (Coke is manufactured for metallurgical purposes by the destructive distillation of certain coals in the absence of air.)

STANDARD ANTHRACITE SIZES

Size Name	Test Mesh, Rd., In. Thru	Over	Max. Undersize, %
BROKEN	4-3/8	3-1/4 - 3	15
EGG	3-1/4 - 3	2-7/16	15
STOVE	2-7/16	1-5/8	15
NUT	1-5/8	13/16	15
PEA	13/16	9/16	15
BUCKWHEAT (#1)	9/16	5/16	15
RICE (#2)	5/16	3/16	17
BARLEY (#3)	3/16	3/32	20
(#4)	3/32	3/64	30
(#5)	3/64	-	

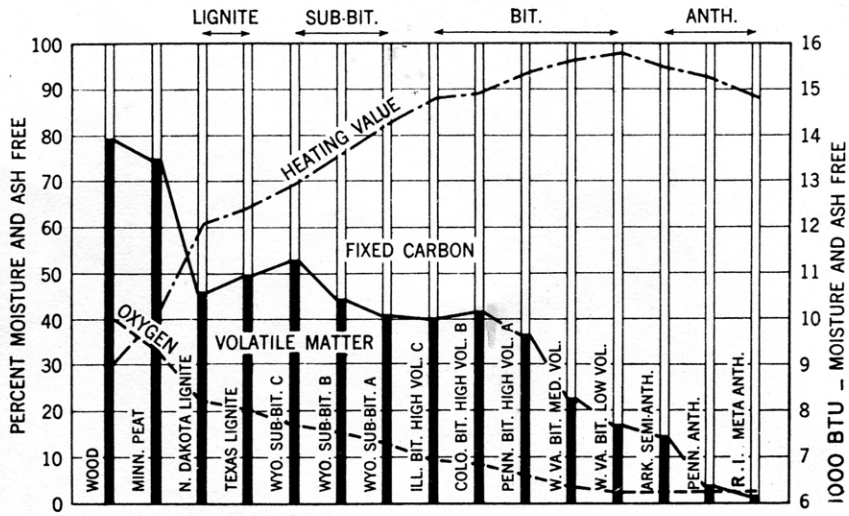
Some coals tend to cake; i.e., form masses of semi-coke consisting of pieces which fuse together when exposed to the fire as the tarry constituents soften. These caked masses impede air flow. The caking tendency can be somewhat reduced by high air flow thru the fuel bed as it enters the furnace, or by "tempering" with moisture as mentioned earlier.

Grindability index is important in considering pulverizer operation and will be discussed under Pulverizers.

TYPICAL ANALYSES OF COALS OF THE U. S. A.

STATE AND COUNTY	Mining District or Seam	Typical Analysis—As Received M	Vol.	F. C.	Ash	Sul.	Btu	Approx. Softening Temp. Deg. F.	Grindability (Hardgrove)
ALA., Jefferson	Mary Lee	2.55	28.10	58.40	10.95	1.00	13,300	2850	62-87
COLO., El Paso	Colo. Springs	22.30	33.30	38.25	6.15	0.40	8,625	2225	38-39
ILL., Franklin	Franklin	9.99	32.82	49.27	7.92	1.03	11,857	2375	53-63
St. Clair	Belleville-Saunton	11.17	39.31	39.20	10.32	4.22	11,223	1995	57-62
Fulton	Fulton	16.33	35.50	37.01	11.16	2.89	10,220	1930	51-68
IND., Clay, Greene, Vigo	No. 3	11.50	38.25	40.45	9.80	4.55	11,550	2125	62-66
Greene, Sullivan, Knox	No. 6	14.90	31.65	46.15	7.30	2.20	11,325	2065	60-65
IOWA, Appanoose, Wayne	Mystic	7.25	36.00	47.50	9.25	3.75	11,500	2050	60-70
Boone		12.30	38.20	43.80	5.70	4.75	10,500	2200	61
KAN., Cherokee	Cherokee	5.00	33.10	52.90	9.00	4.65	12,930	1950	61
Leavenworth	Leavenworth	11.50	35.35	39.95	13.20	4.20	10,900	1965	70
E. KY., Floyd, Letcher, Pike	Elkhorn	3.40	36.75	55.85	4.00	0.75	14,000	2425	50-60
Perry, Breathitt, Knott, Letcher	Harard No. 4	3.75	36.75	55.30	4.20	0.70	13,755	2800	45-55
MD., Allegany	Georges Creek	2.60	19.10	71.35	6.95	1.20	14,135	2410	95-100
MO., Adair	Bevier	11.75	34.50	40.70	13.05	4.80	11,150	1985	72-75
MONT., Carbon	Red Lodge	11.40	35.30	42.80	10.50	1.70	9,900	2145	50-55
N. D., Most Middle and Western Counties	(General)	36.00	29.00	28.00	7.00	0.65	6,600	2050	50

STATE AND COUNTY	Mining District or Seam	Typical Analysis—As Received M	Vol.	F. C.	Ash	Sul.	Btu	Approx. Softening Temp. Deg. F.	Grindability (Hardgrove)
OHIO, Morgan, Noble, Washington, Harrison	Melgs Creek	4.00	36.00	48.50	11.50	4.25	12,250	2400	67
Belmont	Pittsburgh No. 8	5.95	37.80	46.80	9.45	4.20	12,065	2000	50-60
PENN., Luzerne & Lackawanna	Northern Coal Field	3.00	6.10	82.00	8.90	0.70	13,000	3010	25-30
Cambria	Lower Kittaning	2.30	18.65	72.45	6.60	1.44	14,400	2640	107
	Lower Freeport	2.85	22.40	67.05	7.70	1.65	13,960	2465	99
Westmoreland	Redstone	2.10	33.25	53.55	11.10	2.45	13,140	2600	60-70
Allegheny	Upper Freeport	2.50	34.00	54.50	9.00	2.25	13,400	2350	55-60
TENN., Campbell	Jellico	3.50	36.30	52.90	7.30	1.60	13,620	2065	45-55
TEXAS, Bowie S.W. to La Salle	Lignite Fields	33.40	40.40	17.20	9.00	1.10	7,600	2250	53-79
UTAH, Carbon	Castlegate	5.50	39.20	47.80	7.50	0.60	12,500	2200	43-49
VA., Tazewell	Pocahontas	2.90	21.20	71.50	4.40	0.55	14,550	2400	99-105
Wise	Norton	1.40	34.13	58.47	6.00	0.82	14,250	2600	62
WASH., Kittitas	Roslyn	3.70	34.30	48.60	13.40	0.30	12,250	2470	52
Pierce	High Vol. Carbonado	3.80	36.00	51.20	9.00	0.50	13,400	2700	69
VA., Monongalia, Marion, Harrison	Fairmont	1.80	37.55	54.15	6.50	2.20	13,850	2300	50-70
Fayette	New River	2.10	22.50	72.20	3.20	0.65	14,860	2500	90-100
Mercer	Pocahontas	2.60	17.75	75.00	4.65	0.65	14,635	2375	105
Kanawha, Fayette	Kanawha	1.80	35.80	55.70	6.70	0.90	13,500	2800	40-60



All coals have associated with them varying amounts of ash, non-combustible earthy materials, consisting largely of oxides and sulfides of the earth metals, in a range of from 3% to more than 25%. Fusion temperature of these materials which varies somewhat with the atmosphere in which they are burned, ranges from about 1800°F to over 3000°F (anthracite).

FIRING - GENERAL

Larger sizes of coal burning boilers are all fired by pulverized coal, the considerations which govern being to some extent indicated in the discussion which follows. Boilers of any size may be fired by oil or gas.

STOKER FIRING

Stokers have an important place in fuel burning, not only as a transition from hand firing to more modern methods in commercial steam generation, but also as a means of burning certain (including refuse) fuels. Their relative importance as a means of firing coal has greatly decreased however, and application is generally limited to industrial units.

The difficulty of building and maintaining stokers of sufficient size to fire utility boilers cannot be overemphasized. Reliable operation of such huge machines could hardly be expected even if they were not subjected to furnace temperatures. And a stoker failure shuts down the unit; an individual pulverizer or burner failure will at worst force a partial load reduction. Also, heat recovery is limited by the air temperatures which stokers will tolerate.

Favoring stoker application is the minimal cost of fuel preparation as contrasted to the cost of pulverizing the coal and the mineral matter associated with it. Ash disposal favors stoker use. So also does the stoker's ability to operate satisfactorily over a wider load range than most pulverized fuel furnaces, which is important to a plant having a small weekend or night load.

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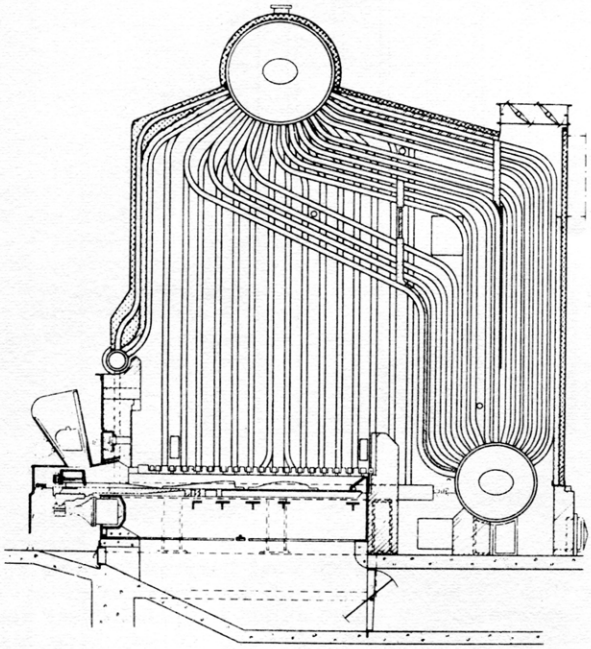
Stokers may be classified in two general types, depending on whether the coal is fed from below or above the fuel bed, as underfeed and overfeed.

UNDERFEED STOKERS

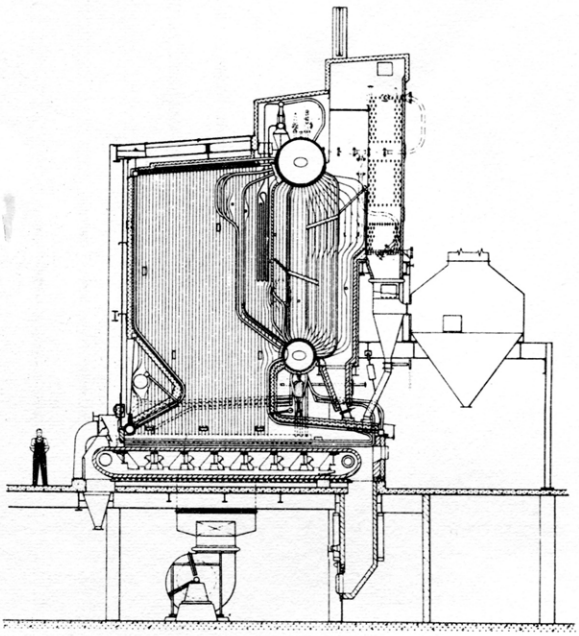
Underfeed stokers, either single or (rarely) multiple retort, consist essentially of a trough or troughs into which coal is pushed by rams or screws. Part of the combustion air is introduced into the fuel bed through tuyeres or grate bars. Movement of the fuel discourages the formation of large coke masses. Volatile matter is distilled off the coal in these troughs or retorts and burns above the incandescent fuel bed. The partly coked and somewhat caked coal then falls onto the air admitting tuyeres or grate bars where the fixed carbon is burned out. Progressively the fuel is pushed sidewise or forward until the refuse is discharged to the ashpit.

OVERFEED STOKERS — Traveling grate stokers (chain or bar grate type).

The terms "chain grate" and "bar grate" merely describe the surface which carries fuel fed by gravity from a hopper, supports it throughout combustion, and deposits the refuse in the ashpit. A chain grate surface consists of a series of links strung on rods in a staggered arrangement and moved by sprockets and/or drums. The bar grate surface consists of rows of keys strung on bars which are in turn carried by chains driven by sprockets. Each has its advantages: chain grates tend less to retain siftings and clinker accretions; bar grates are less affected by wear, and are easier to repair.



C-E Steam Generating Unit, Type VU-10, fired by Type E Stoker (steam piston drive). Approximate capability range, 10,000 - 40,000 pounds of steam per hour.



C-E Type VU-50 Boiler fired by C-E Traveling Grate Stoker burning midwest bituminous coal. Capability, 100,000 lb. steam/hr. at 850 psi, 585°F.

Traveling grate stokers are not provided with means to break down incipient cake formations, hence are suitable for free-burning coals (and to some extent, lightly caking eastern coals at reduced rating) only. Since they merely carry the fuel as a conveyor, high ash content has no abrasive effect on stoker parts. It does, however, adversely affect ashpit loss.

SPREADER STOKERS

The spreader stoker consists of either a dumping or traveling type of grate onto which coal is thrown by a distributor (a series of spreader paddles) attached to a rotating shaft below the coal hopper. Alternatively, the fuel may be propelled by jets of air or steam. Firing rate is controlled by a metering feeder between the hopper and distributor. Much of the coal is ignited in suspension and because most of the volatile matter is distilled off before the coal reaches the grate, the stoker burns either free-burning or caking coals satisfactorily.

To obtain uniform distribution of fuel, advantage is taken of the fact that the energy imparted to pieces of coal when struck by the distributor paddles varies with the size of the particles. Distributor speed may be adjusted by means of a variable speed transmission.

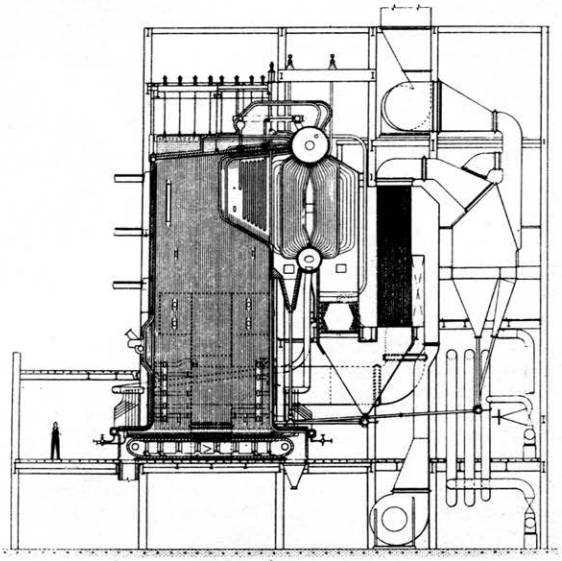
With mechanical distributors, the smaller particles fall toward the front of the grate and larger pieces toward the rear. To permit these larger pieces a longer time to burn, the grates of continuous discharge spreader stokers are made to travel forward toward an ashpit conveniently located under the front of the stoker.

The continuous-discharge spreader stoker combines the advantages of the spreader stoker and the traveling grate stoker. The spreader stoker's characteristic quick response to load changes and ability to burn a wide variety of coals supplement the low ashpit loss and continuous cleaning features of the traveling grate. The elimination of periodic dumping simplifies operation, and adapts the continuous-discharge spreader to larger units and somewhat higher continuous burning rates than the dumping type spreader. Accurate distributor adjustment is not as important as with the dumping type spreader, since the continuous grate movement helps maintain a uniform fuel bed.

GENERAL

All modern stokers are arranged for zoned air admission, often with part of the air admitted above the fuel bed to promote turbulence. Zoned air admission is desirable not only to control excess air but because of its influence on ignition and caking. The necessity of cooling fuel supporting surfaces by combustion air limits both preheated air temperature and the proportion which may safely be diverted as overfire air.

Although some ash is essential in a stoker coal to protect the grate from radiation, it is objectionable as a diluent which carries some unburned fuel



C-E Type VU-40 Boiler with high set Spreader Stoker, designed to burn bark, oil, natural gas and coal. Note baffle-less boiler (to avoid cinder erosion), cinder return to furnace, Economizer and Tubular Air Heater.

to the ashpit with it. It also increases fuel-handling and ash-disposal cost and may interfere with furnace operation, thus increasing operating and maintenance costs.

Sulfur is particularly objectionable since its combustion creates, in combination with water vapor, sulfurous and sulfuric acid. Not only are these acids highly corrosive where condensation occurs, but they tend to retain ashy deposits and cause plugging at the cold end of the unit. High sulfur is often present as iron pyrites, thus an indication of a clinkering tendency.

SIZES

Stokers are proportioned on the basis of grate heat release rates which may range from 200,000 Btu/hr for small single retort stokers to 1,000,000 Btu/hr or more for large spreader stokers where part of the fuel is burned in suspension, per square foot of projected grate surface.

This area determines the furnace cross section. Furnace volumes are proportioned on the basis of furnace heat release rates which may range from 25,000 to 50,000 Btu/ft 3/hr., depending on installation size, type of stoker, probable load factor, and the amount of furnace heat absorbing area.

Traveling grate stokers are used in sizes from about 50 sq. ft. (10,000 lbs. steam/hour) to 670 sq. ft. (275,000 lbs. steam/hour). Dump type spreader stokers might cover the same range but since grate lengths over sixteen feet are awkward to operate, a practical limitation corresponds to about 125,000 lbs. steam/hour. Not subject to this limitation, the continuous discharge stoker may range up to 200,000 lbs. steam/hour or more.

The size range for single retort stokers is about 30 to 125 square feet corresponding to about 5,000 to 40,000 lbs. steam/hour. Multiple retorts, now obsolescent, have been built from sizes somewhat below this maximum up to 15 retorts in width and capable of generating 300,000 lbs. steam/hr. (largest = 530,000 lbs. steam/hour). At the larger end of the range and from there up economics certainly favor pulverized coal.

CONTROL FOR SPREADER STOKERS

Generally, firing rate is varied by simultaneous control of fuel and air. On other than spreader stokers, an exact consonance is not essential since slight variations in fuel bed conditions are not serious. With pulverized coal, oil, and gas, any variation in the ratio of air and fuel feed is immediately reflected in furnace operation and efficiency. Because of the thin fuel bed and small amount of fuel in the furnace the spreader stoker is also sensitive to synchronization of air and fuel feed. Automatic control of this relationship is essential to efficient and smokeless operation.

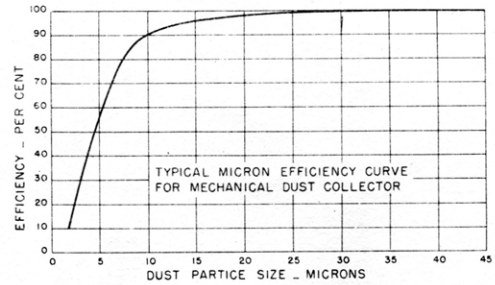
FLYASH AND SMOKE

A discussion of flyash and smoke is inserted at this point because of their importance in connection with spreader stokers. The emission of flyash from the furnace of a spreader stoker follows a characteristic between that of other stokers and pulverized coal. Smoke, as contrasted with flyash, usually consists of unburned carbon particles resulting from the dissociation of hydrocarbons in the furnace, hence these particles are molecular in size except when they tend to agglomerate. Smoke or ash density is defined in terms of the Ringelmann chart by comparing its appearance to that of a series of squares formed by intersecting black lines of varying spacing and width on a white chart. This color density is not a true measure of the amount of solid material leaving a stack, and the reading will vary with the position of the observer, clearness of the day, stack size, and wind velocity and direction.

With pulverized-coal firing, up to 80 per cent or even more of the ash leaves the furnace (except where a slagging-bottom furnace is employed) – carrying with it an amount of unburned carbon, which may be quite considerable – the combustible in the flyash varying from perhaps one to twenty five percent. If no dust catcher is provided, much of it leaves the stack. Particles are probably all sub-325 mesh (44 micron) and may travel long distances before settling out. Except at high combustion rates, the amount of flyash from stokers or hand-fired furnaces is not serious from the carbon loss standpoint, but the particle sizes are such that if they leave the stack they will fall over a small area nearby.

Flyash from a spreader stoker is much greater in amount than from other stokers, and the particle sizes are much larger than from pulverized coal. Therefore, advantage is taken of all points in the gas path where flyash will settle out because of change in direction of gas flow or low velocity, to collect this material and return it to the furnace where some of the carbon will burn and the ash fall to the grate. Unburned carbon losses are higher with spreader stokers than with other types of firing.

Absolute elimination of flyash or cinder emission is not commercially feasible, but devices designed for the purpose are effective to a maximum of about 95 per cent. Mechanical dust catchers are most effective on particles of relatively large size, and electrostatic precipitators on particles of small size. Mechanical collectors are usually recommended for use in conjunction with spreader stokers, not only because of particle size but also because electrostatic precipitators have a reduced effectiveness on high-carbon dusts.



Typical micron efficiency curve for mechanical dust collector.

It is difficult to define what constitutes a nuisance. Many legislative bodies have formulated ordinances defining stack emission in terms of both color and solids density. The ASME proposed model dust ordinance is based on a limit not exceeding .85 lb. per 1000 lbs. of gas emitted. Most commercial dust collectors can hold emission to this limit if designed for the expected particle size range.

PULVERIZED COAL FIRING

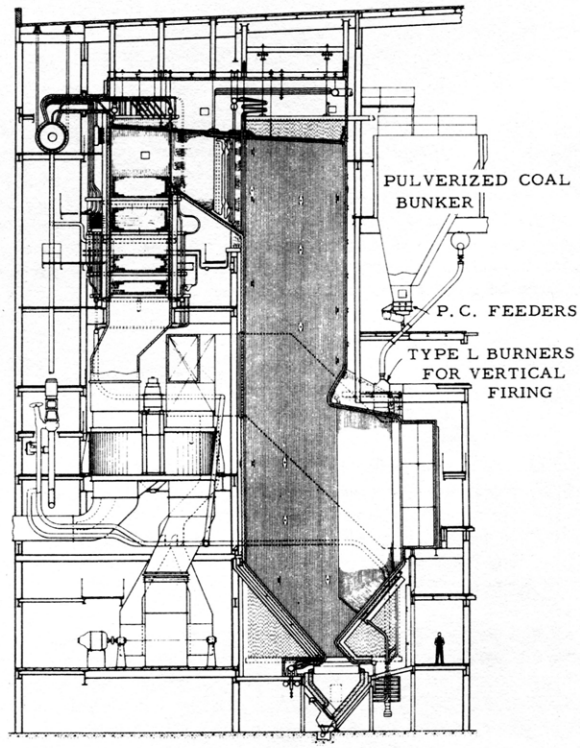
DIRECT & STORAGE SYSTEMS

With the early pulverized coal fired installations, pulverizers did not discharge directly to the furnace, and were often housed in a separate building outside the boiler house. The coal was usually dried externally, then fed to the pulverizers, and the pulverized product conveyed to bunkers above the pulverized fuel feeders through which it was fed to the burners.

This indirect or storage system has the advantage that the coal-feed and coal-air ratios to individual burners are under the direct control of the operator, and less mill capacity is needed for a given load since the mills always operate at full load. The mills may not be operated during peak load periods if auxiliary power saving is important, depending on load factor and pulverizer size selection.

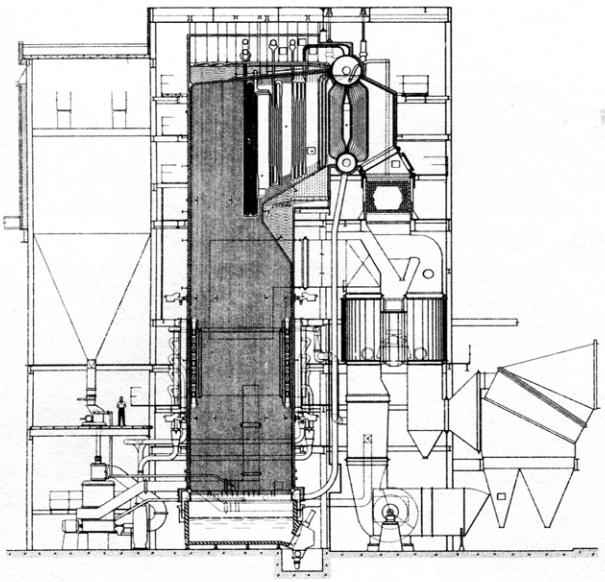
Among its disadvantages are duplication of bunkers, conveying and feeding equipment, etc., which necessitate large capital expenditures for buildings and equipment; higher auxiliary power requirement; coal drying in the mill allows for less moisture range in fuel; the pulverized fuel must be separated from the air carrying it from the mill or transport system and the equipment to do this requires considerable space; disposal of dusty air from the mill vents is a difficult and costly problem. Further, the storage of pulverized coal introduces a hazard which must be safeguarded; pipes and conveyors present maintenance problems; and operating difficulties may result from coal sticking in the bunkers because of moisture condensation.

Indirect firing (storage system) has been almost entirely superseded by direct firing. In this



Indirect (Storage) System for burning pulverized coal

system firing rate is controlled by the raw coal feed to the pulverizers or indirectly by pulverizer differential, and the pulverized product is blown by the pulverizer exhausters or blowers to the burn-



Direct Fired System for burning pulverized coal: C-E Raymond Bowl Mills and Tilting Tangential Burners firing a pressurized VU-40 Boiler (450,000 lb. steam/hr at 1310 psig, 955°F)

ers. Coal is dried in the mill by the use of hot primary air; higher coal-air mixture temperatures can be used as there is no hazard from bunker fires.

Mill capacity must correspond to the maximum load demand, however, since there is no pulverized coal bunker storage. Mill maintenance cost and power consumption are therefore somewhat higher than with indirect firing because of part time operation at fractional loads. This is more than offset by the savings resulting from the absence of conveyors, pulverized coal feeders, primary air fans and collectors.

Burner control is not as good as with the indirect fired system, as the mill characteristics usually impose upon the burners the necessity of handling the amount of primary air which the mill operation requires. This latter varies somewhat with the load, and since the air required for the mill cannot be reduced in direct proportion to the coal feed, the primary air per pound of coal will be high at low load tending to making ignition unstable. The relationship is, however, influenced by the necessity of maintaining under all conditions a velocity which will avoid settling of coal dust.

Successively larger pulverizers have been designed to accommodate the trend toward larger steam generating units without the addition of more burners and pulverizers.

PULVERIZERS

As is to be expected, there has been a wide variation in the devices designed to pulverize various coals and each may be particularly suitable for some application. The characteristics to be desired are dependable performance, uniform or adjustable product, low operating cost (principally low power cost), low maintenance cost, quick response, quiet operation, and ability to handle wet coal.

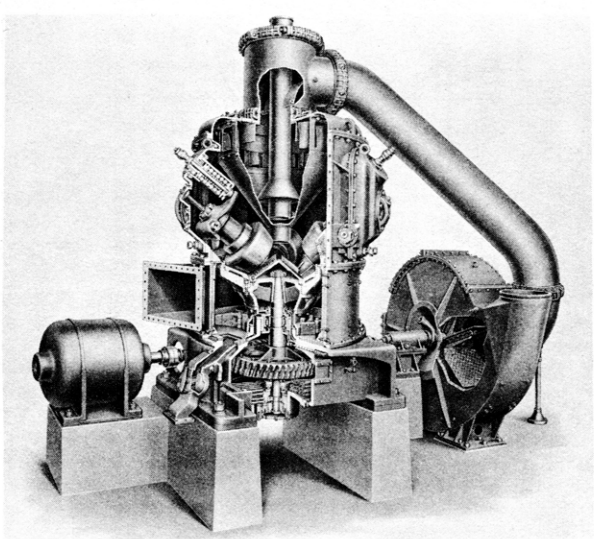
Early pulverizer designs followed cement grinding practice to some extent in using ball mills. These comprise cylinders containing cast-iron or alloyed steel balls which crush the coal as the cylinders rotate. As the balls must roll or drop on the coal charge, the speed (hence, capacity) is limited to that at which centrifugal force would overcome gravity and the balls cease to roll.

Grinding elements are simple, but the ball mill is noisy in operation, control of fineness is poor, and power consumption per ton of product is high, particularly at light loads. Performance has been improved by baffling the mill and sweeping it with air to remove the pulverized product. The rather large amount of coal storage in the mill makes it responsive to sudden load increase, but this characteristic becomes a liability in the event of trip-out. This type of mill is particularly suitable for grinding anthracites and similar fuels.

There are several "impact type" mills, most arranged with horizontal shafts, in which coal is struck by hammers or pegs and broken by impact. All impact mills are high-speed mills (1200 to 1800 r.p.m.) and they contain relatively little coal when in operation. Maintenance cost is rather high.

In the Raymond Roller mill the material to be pulverized is thrown against a vertical ring and ground by rollers suspended from a rotating spider and swung out against the ring by centrifugal force.

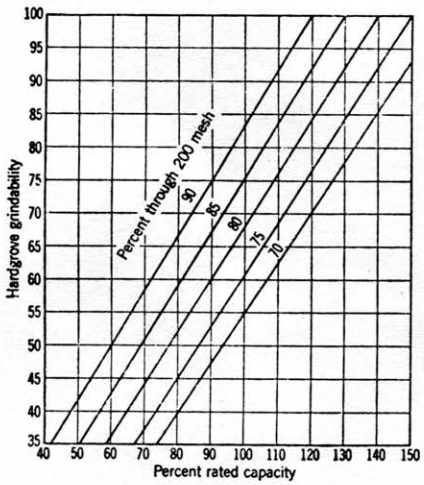
The most popular Raymond pulverizer for grinding coal is the Bowl Mill. Coal is fed into a rotating bowl and thrown outward by centrifugal force to the rotating ring where it is pulverized by rolling under spring-loaded rollers. Air sweeps by the bowl and removes the product to the classifier, from which large particles are returned for further grinding. This is an intermediate speed pulverizer (vertical shaft speed about 65-100 rpm) which, with its quiet, vibrationless operation, combines very satisfactorily the desirable characteristics emphasized in the following paragraphs, including low power consumption and low maintenance.



Cut away view of C-E Raymond Bowl Mill and Exhauster, typical of larger sizes. Design shows center coal feed.

It is of interest to consider some of the factors which influence these desirable characteristics. Dependability requires that a mill will not be damaged or shut down by tramp iron or other foreign material often removed by a magnetic pulley. Preferably, shut downs should not be required for lubrication or too frequently for replacement of worn parts. Uniformity of product requires the avoidance of overgrinding and some means of classification. This can best be accomplished by removing the pulverized product to an air-swept classifier and returning the coarse material to the mill for further grinding. Adjustments to the classifier should permit fineness control. Both maintenance and power consumption are related to over-grinding, and the former is also related to the extent to which grinding surfaces are "cushioned" by coal. In comparing power consumptions it must be remembered that the mill motor usually drives the mill exhauster which not only supplies the air to clear the mill, but also conveys the air-coal mixture to the burners or separator. The power required to convey coal to the burners varies considerably in different installations, but is about one-third the total. Quick response is a function of the rate at which mill discharge can be varied, and is related to the amount of coal in the mill (circulating load) and the air flow. Ability to handle wet coal is related to the intimacy of mixing of raw feed with the partially dried product.

There is an appreciable difference in the friability of coals. To provide a yardstick which will enable designers to select and compare pulverizer performance, the Hardgrove grindability index is usually used. Fifty grams of material screened to plus 30 mesh minus 16 mesh is placed in the Hardgrove grindability machine and ground for 60 revolutions. The sample is then sieved for twenty minutes on a 200 mesh screen and the amount which passes thru determined by weighing what remains and deducting from the original sample weight. Hardgrove grindability index = 13 + 6.93W, where W = minus 200 mesh (74 micron) material.



Capacity chart for coal: C-E Raymond Bowl Mill.

Hardgrove grindability, ranging from about 20 for very hard coals to more than 100 for soft coals, is a guide in predicting capacity, fineness, and power consumption for a given pulverizer. (It is interesting to note that altho anthracite is harder than bituminous coal, low volatile bituminous is generally more friable than high volatile.)

Abrasiveness, which determines wear and maintenance cost, is not directly related to grindability.

No pulverizer can pulverize economically a substance carrying a large amount of surface moisture. Total moisture is not a good comparison basis, since inherent moisture varies widely with coals of different origin. Advantage is taken of the greatly increased area of the coal particles and turbulence in the mill to remove most of the surface moisture by using hot carrier air for flash drying; this process may be facilitated by mixing dry classifier returns with the raw coal. Since the sensible heat in the air quickly becomes latent heat of vaporization, the temperature of the air-coal mixture is substantially lower than that of the entering air. The pulverizer's capacity to dry depends on the amount of heat which can be carried by the carrier air at safe temperature, plus most of the heat degenerated from power required to grind.

Thus the capacity of a pulverizer may be limited by its grinding capacity or its drying ability.

The degree of fineness to which coal should be pulverized depends upon its volatile content; also to some extent upon the type of burner, the amount of water cooled surface exposed to the flame, and the distance which the combustion gas has to travel before entering the tube bank. Although the American Boiler & Affiliated Industries recommends 70 per cent through a 200-mesh screen as a desirable minimum for bituminous coal, 75 to 85 per cent through a 200-mesh is sometimes employed where the volatile is 25 per cent or less and a turbulent-type burner with short gas travel is used. Conversely, 65 per cent through a 200-mesh may suffice for some high-volatile coals and tangential burners. It is most important that the amount not passing through a 50-mesh be kept to a minimum (one per cent or less). For anthracite, 85 per cent through a 200-mesh is generally necessary.

PULVERIZED COAL BURNERS

Complete combustion requires that at a temperature sufficiently high for ignition every particle of fuel must come in contact with oxygen for long enough for the combustion reaction to occur. Turbulence is necessary to scavenge combustion products from the surface of fuel particles and to supply oxygen.

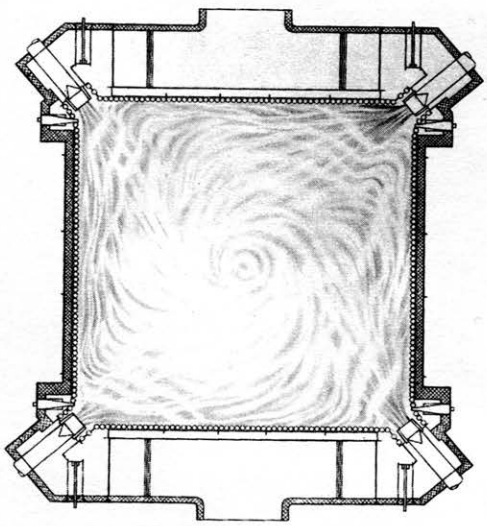
Fuel streams enter a furnace at a velocity considerably above the rate of flame propagation. Ignition stability depends on a flow pattern from the burner which causes eddy currents at the stream edges.

While ash pits are provided in all pulverized coal fired boilers, not all of the ash is deposited in the ash pit directly. Ash particles become molten in the flame, then re-solidify. Part of the ash adheres to or is deposited on furnace walls, boiler tubes, and superheaters, and, when dislodged, falls to the ash pit. Part is deposited in dust hoppers; much passes thru the unit to be removed by a dust collector. (Approximate distribution: Ashpit, 20%; dust hoppers, 5%; dust collector, 75%. Slag bottom furnaces, however, may retain 50 - 60% in the ashpit.)

TANGENTIAL BURNERS

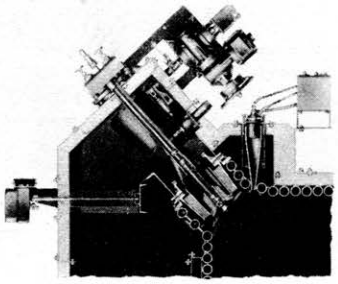
Prominent among pulverized coal burners is the tangential (Type T or Type TT) burner used for corner firing. These burners with alternate fuel and air nozzles (oil and/or gas may be burned with or without coal) are located in the walls or corners of the furnace, directed to obtain a rotary motion within the furnace. Impingement of the streams produces the turbulence and mixing necessary for rapid and complete combustion.

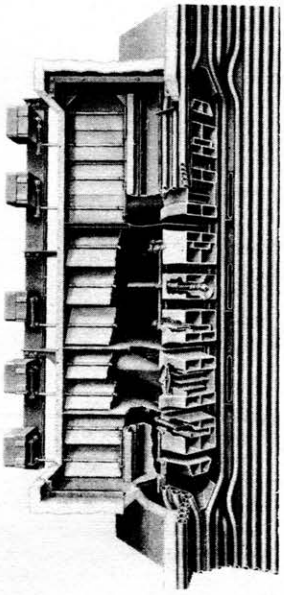
The firing method has definite advantages particularly for large steam generating units in effective utilization of furnace volume, promotion of heat absorption by the furnace envelope, and dependably low carbon loss. Individual burners are comparatively simple and their design and location minimizes exposure to furnace heat. Good operation is less dependent on fuel and air distribution than with other burners.



Plan view showing C-E Tangential Burners arranged for corner firing. Note ignition torches, air ducts and dampers, completely water cooled furnace.

Another important advantage lies in the use of tilting tangential (Type TT) burners to provide steam temperature control. Locating the burners some distance above the bottom of the furnace and arranging the nozzles so they may be tilted (thirty degrees) above or below horizontal, permits, in effect, an adjustment of the furnace size to suit the load. Tilting tangential burners thus permit wide range control of steam temperature and furnace slagging conditions.

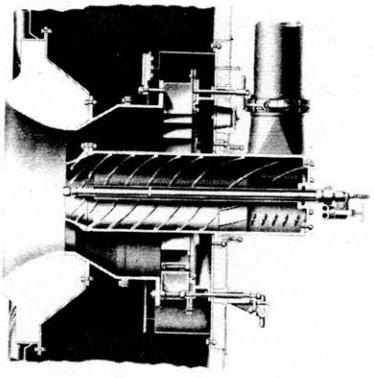




Views of C-E Tangential Burner, showing oil atomizer, ignition torch with control cabinet, and controls for burner tilt and air dampers. Note skin casing and insulation behind furnace tubes.

HORIZONTAL TURBULENT BURNERS

Another burner commonly used is the horizontal turbulent (Type R) design. Both the coal-air mixture thru a center nozzle and secondary air around the nozzle are made to rotate in an effort to obtain uniform distribution and thorough mixing of the fuel and air as they enter the furnace. All combustion air is admitted thru the burner. Adjustment is provided in the coal-air stream to promote uniform distribution of fuel around the periphery of the burner. Adjustment of tangentially arranged

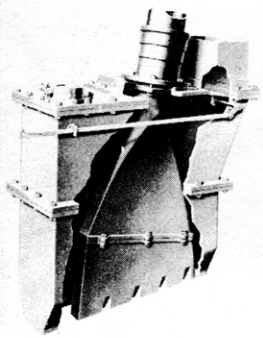


Section of C-E Type R Burner for oil and pulverized coal.

vanes permits control of circumferential velocity of secondary air. The burner has virtually a self-contained flow pattern; ignition is promoted close to the burners by a part of the flame which flows into the vortex. This built-in characteristic gives the burner the highest turn-down range of all pulverized coal burners.

VERTICAL BURNERS

Early successful pulverized coal installations were fired by a row of fantail (Type L) burners directed vertically downward thru an arch which formed the roof of the furnace. Secondary air was admitted thru ports in the front furnace wall as the flames swept downward, and combustion continued as the flame turned upward in the furnace. Later refinements introduced part of the combustion air, called tertiary air, around the burner nozzle.



C-E Type L Burner for vertical firing.

This firing method is somewhat limited by the amount of coal which can be delivered per nozzle, hence by furnace width. It cannot be adapted as easily as other methods to multiple fuel arrangements, particularly gas. Present use is generally restricted to anthracite or waste fuels which do not ignite readily; flame shape and the turbulent effect at the stream edges due to aspiration promote ignition.

IGNITION BURNERS

Wide, rapid load swings, particularly at low loads, tend toward ignition instability. Also, with one mill operation there is a possibility of flame loss due to momentary interruption of coal flow. To minimize hazard and facilitate ignition small gas or light oil pilot burners are often provided. These have a capacity of about 3 - 7 X 10^6 Btu/hr per burner. Remote ignition may be obtained by the use of gas or oil ignitors.

A group of tangential nozzles may be provided with pilot burners in all four corners at one elevation and ignitors, to be lit as mills are put into or removed from service, at all elevations.

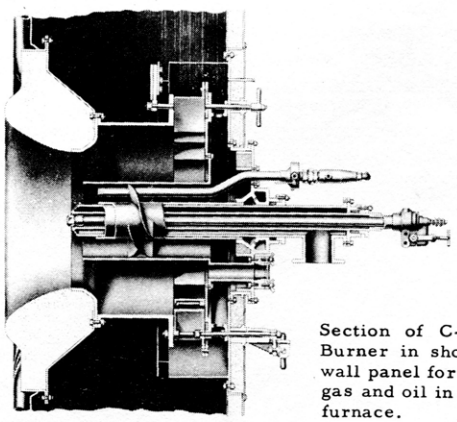
GAS AND OIL FIRING

COMBINATION BURNERS

With all burners, mechanical mixing of fuel and air as well as a flow pattern and furnace shape which will stabilize ignition are necessary if complete combustion is to be obtained with minimum excess air. Time alone is insufficient.

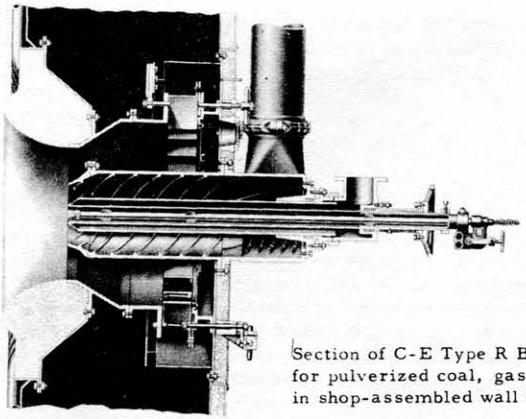
Early oil and gas burning practice used a multiplicity of small burners, but development has been toward fewer burners of higher capacity. This reduces cost, ducts and piping considered, and simplifies operation.

Combination burners permit the use of more than one fuel, as may be dictated by the limited availability of process by-products or the profitable utilization consistent with price fluctuations, of alternatively available fuels. Such burners permit taking advantage of favorable fuel price differentials. Combination burner design leans most heavily toward the accommodation of the more bulky fuel, blast furnace gas or pulverized coal with its carrier air, with adaptation to the more concentrated fuel such as oil or natural gas.



Section of C-E Type R Burner in shop-assembled wall panel for firing natural gas and oil in pressurized furnace.

In horizontal turbulent burners, oil guns are inserted thru a tube in the center of the coal nozzle. Natural gas may be admitted thru a pipe concentrically arranged outside the oil burner tube, or thru a perforated burner ring outside the coal stream. Air registers for horizontal oil and gas burners do not require elaborate adjustment and



Section of C-E Type R Burner for pulverized coal, gas and oil in shop-assembled wall tube panel.

may be simplified by the use of stationary vanes (Type SV). Oil, gas, and coal firing can readily be combined in tangential burners, the nozzles being alternated with the air nozzles. Vertical firing does not lend itself to this combination.

Gas and oil burners are sometimes used for supplemental firing in stoker furnaces. These may utilize refinery, coke oven, or blast furnace gas available as by-products, supplanting the stoker fuel in part, or may regularly assist in carrying load. In general, stoker furnaces are not suitable for combustion of these fuels at heat release rates corresponding to the stoker's maximum and there is danger of damaging the stoker surface if it is not protected from radiation in some manner.

GAS BURNERS

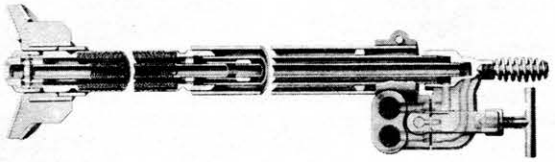
Gas burner nozzles may be designed with a series of small holes for distribution of gas in the air stream or a single nozzle opening of suitable size, depending on the application, method of air admission, and cleanliness of the gas. Some gas burners pre-mix part of the combustion air. Blast furnace gas burners must be large enough to pass large volumes of low calorific gas containing considerable dust. Small jets firing such a gas would soon be plugged with dirt.

A comparatively new and interesting application is the burning of the gas and air from an oil catalytic cracker. The waste gas leaves the catalyst regenerator at a temperature of 1000 - 1200°F and contains 3-8% CO. Its use for steam generation salvages the available sensible heat and the fuel value of the CO, and reduces atmospheric contamination.

OIL BURNERS

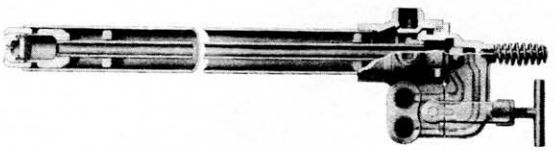
Oil burner guns for power boilers are usually described by the method used in atomizing the oil at the tip as: mechanical atomizing, steam or air atomizing inside or outside mix type, and rotary cup.

Rotary cup burners depend for atomization on centrifugal force. Energy is imparted to the oil oy a rapidly spinning cup, droplets flying off the rim as a mist.



C-E Air or Steam Oil Atomizer with flexible tubes for adjustable nozzles.

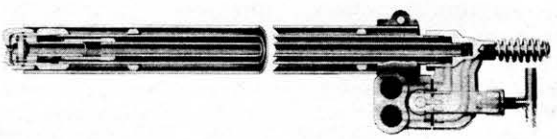
In steam atomizing burners streams of oil and steam impinge in a mixing chamber where the energy in the steam heats and atomizes the oil, and the mixture then enters the furnace. Oil viscosity need be only low enough to permit pumping, about 200 SSU.



C-E Straight Mechanical Oil Atomizer with rigid tubes for stationary nozzles.

Mechanical atomizing oil burners depend for atomization on the energy in the oil by virtue of its pressure, that is, the conversion of this energy to velocity. The oil flows thru tangential passages in the burner tip and emerges thru a central hole with sufficient rotative velocity to cause atomization, minute droplets flying off from the tip circumferentially. The required oil viscosity, about 150 SSU maximum, necessitates heating the heavier oils.

Firing rate of all burners is controlled by varying oil pressure; for a given system resistance, the pressure variation is as the square of the rating. The atomizing effect of steam and rotary cup burners is not dependent on oil pressure drop thru a nozzle, hence these burners function satisfactorily over a wide load range. This is not true of straight mechanical atomizing burners since energy for atomization depends on pressure, about 100 psig minimum. Unless the system is designed for very high pressure at maximum load, atomization is poor and burners drool or throw large droplets of oil at low load. While this can be accommodated by changing tips it necessitates taking burners out of service successively which temporarily upsets air distribution.



C-E Wide Range Mechanical Oil Atomizer.

The limitation can be minimized by the use of wide range mechanical burners. In this design oil is pumped to the burner tip at a constant rate, passing thru tangential slots at high velocity. Part of the rapidly spinning oil passes into the furnace, the balance is returned thru another passage to a tank or booster pump inlet. Firing rate is controlled by varying the return line pressure.

While the steam atomizing burner has some advantages, particularly for starting and low load operation, there is often an objection to the use of steam. The amount of atomizing steam is less than one per cent of that generated at full load, but its use entails the loss of treated water. There is a slight increase in flue gas moisture, with its implications as to air heater or economizer corrosion. Energy wise, there is very little difference between steam and mechanical burners in atomization cost when the lesser amount of unburned carbon with the steam atomizing burner is considered.

FLAME SUPERVISION

Resumption of fuel flow to a hot furnace after accidental flame failure may cause a very serious explosion. Oil and gas burners are therefore often monitored by flame failure devices utilizing radiation sensitive eyes which will shut off fuel and/or sound an alarm in the event of such failure. A further refinement may include controls which will prevent relighting until the furnace has been purged.

This is an essential safeguard to remote operation.

FURNACES

PROPORTIONS

In a stoker fired furnace, the combustion reaction proceeds very rapidly (but not to completion) in and adjacent to the fuel bed. With spreader stokers, however, much of the fuel burns in suspension. Stoker firing does not demand as much furnace volume as do pulverized coal, gas, and oil. However, some zones are rich and others deficient in oxygen; smoke might result if means were not taken to promote turbulence.

Suspended arches, overfire air or steam jets promote mixing and turbulence in the furnace. Their use is generally restricted to furnaces for traveling grate stokers. Location is largely a matter of empirical design based on experience and checked against tolerable velocities. Stoker furnace design is to some extent a matter of enclosing the stoker and boiler in a heat resisting envelope, yet flame travel and retention time (furnace volume) cannot be overlooked.

It is desirable to complete combustion within the furnace. If flame continues into the tube bank of boiler or superheater damaging local high temperatures may occur, and performance is hard to predict. Certainly incomplete combustion and smoke will result if the gas temperature falls below the ignition point.

The shape of a furnace must consider the firing method, taking cognizance of the fact that unused volume does not contribute to completion of the combustion reaction. Other factors may be considered in determining width, such as gas velocity entering the boiler, or steam release rate per foot of drum length.

Large completely water cooled coal burning furnaces are proportioned to obtain a gas temperature entering the first tube row and/or the superheater which will not cause excessive slagging of the ash. The amount of furnace heat absorbing area required to accomplish this may influence furnace size. Thus furnace proportioning must consider both volume, which is related to time required for combustion, and radiant heat absorbing area which determines gas temperature leaving the furnace.

Theoretical flame temperature for a given fuel depends on excess air and entering air temperature, and is independent of combustion rate. Actual temperature in the furnace depends on the rate at which heat is evolved and that at which it is absorbed. Water cooled surfaces in a furnace absorb heat principally by radiation, hence the rate varies with the emissivity and about as the difference of the fourth powers of the absolute temperatures.

In practice all heat absorbing surfaces are masked to some extent by dust or slag deposits which insulate the tubes and increase the temperature of the surface which the flame "sees". Therefore theoretical heat transfer figures must be tempered by the application of "furnace effectiveness factors" as determined in actual practice. These consider the nature of the surface, type of firing and anticipated fouling and are applied to the "effective projected radiant (heat absorbing) surface" or EPRS.

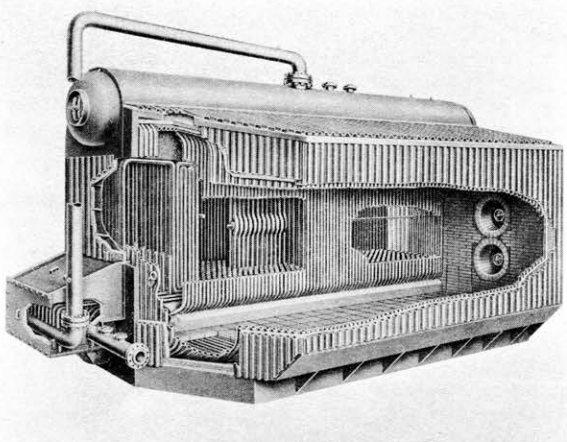
As furnace size increases, volume (for similar shapes) increases as the cube and wall area only as the square of corresponding lineal dimensions. In large furnaces, therefore, it is sometimes necessary to use a center wall of heat absorbing tubes to increase the EPRS. The controlling factor in determining the size of such furnaces is the heat release in Btu per hour per square foot of effective projected radiant heat absorbing surface.

Satisfactory heat release rates vary with furnace size, proportion, construction, and type of fuel. For fuel oil an acceptable maximum for a medium size water cooled furnace is about 35,000

Btu/cu. ft. hr.; natural gas permits a slightly higher rate; coal requires about 20,000 to 25,000, depending on ash softening temperature and EPRS.

Heat release rates per square foot of effective radiant heat absorbing surface vary widely - from perhaps 60,000 to 200,000 Btu. Average heat absorption rates are somewhat less than half these figures. As might be expected, the rate of heat release and heat absorption differ considerably in different parts of the furnace. Large gas and oil furnaces are generally limited to average heat release rate of about 150,000 Btu/sq. ft. EPRS, and coal furnaces to about 100,000.

While the above limits apply generally to stationary practice there are exceptions. Modern "package boiler" design places a premium on size and price, and furnace sizes tend toward marine practice as described below. Cellulose fuel furnaces may have very high heat release rates, but the fuel contains considerable moisture the evaporation of which reduces flame temperature.



C-E Type VP (package) Boiler.

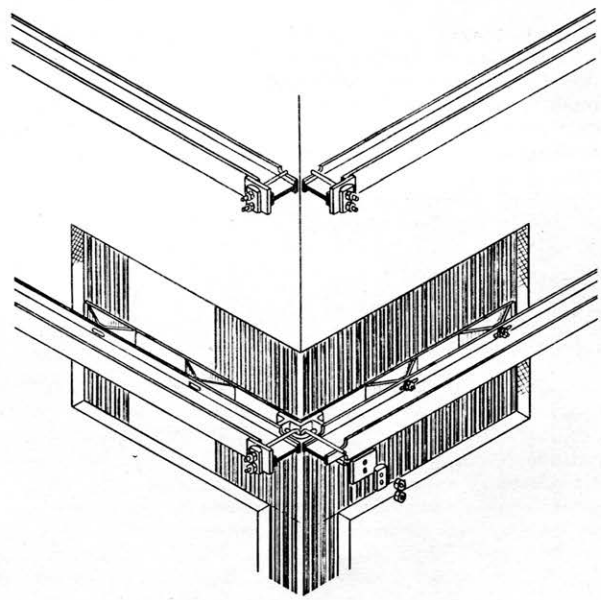
Sometimes comparisons are made to steam locomotive and marine boilers without considering that the boilers operate under different conditions and are designed with these conditions in view. Maximum heat release rate in a marine boiler may be as high as 75,000 Btu/cu. ft/hr. (or 1,500,000 Btu per sq. ft. EPRS) or more, but this is accomplished at the expense of relatively high maintenance cost, and to some extent at a sacrifice of efficiency. This practice is justified by the need to keep size and weight of boilers and furnaces at a practical minimum in comparison with cargo space. However, it is not usual to operate marine boilers continuously at maximum rating.

PRESSURE FIRED FURNACES

Most furnaces operate at a pressure slightly below that of the atmosphere. This prevents local overheating due to furnace gas leakage and permits the opening of furnace observation or access doors without serious danger. To obtain a sub-atmospheric pressure, a stack or induced draft fan is provided to overcome flow resistance from furnace to outlet.

There is a current trend toward pressure firing in which the furnace is operated at a pressure sufficient to force the combustion products thru the unit. Principal advantage is the elimination of the induced draft fan.

Induced draft fans are comparatively large, since they must handle gas at high temperature. They must be designed to resist both corrosion and expansion, and often to handle a dust laden gas. A forced draft fan selected to overcome all system resistance is less expensive and requires less power to drive than two fans - forced and induced - to accommodate respectively the losses from atmosphere to furnace and furnace to atmosphere.



Furnace construction for pressurized firing.

However, pressure furnaces must be carefully sealed against leakage and designed to maintain tightness despite wide temperature changes. Burners and pulverizers must also be designed for operation under pressure; leakage cannot be relied on to provide cooling or dust scavenging; doors must be provided with aspirating devices to prevent flame or hot gas from blowing out when they are opened.

These considerations warrant careful economic study.

WATER COOLED FURNACES

The original purpose of water walls was to protect or supplant the refractories used in furnace construction and to lower ashpit temperature to prevent slagging. Brickwork failures and firmly adhering slag accretions limited firing rate, shortened operating periods, and caused expensive maintenance.

Modern furnaces may operate without interruption for a year or more, being taken out of service only for required annual insurance inspection.

In modern boilers furnace cooling is used to the fullest extent consistent with economy of design and firing characteristics. In all cases, furnace water cooling surface is made part of the "boiler" circulation; it may often be difficult to distinguish between "furnace" and "boiler" in this respect.

Any furnace cooling will improve refractory maintenance, at least by reducing the severity of the temperature conditions to which it is subjected. Large furnaces, however, are usually completely enclosed in a heat absorbing envelope; with large power generating units this is a requirement of the design for reasons other than refractory protection, as will be discussed later.

All water walls consist of a series of tubes terminating in drums or headers. To provide adequate ligament strength, closely spaced tubes may be arranged as bifurcates or trifurcates, with ends swedged to a smaller diameter, or by a staggered arrangement at their terminals.

Heat absorbing area may be extended by fins welded to the tubes, but this practice is now limited to cooler locations or small areas around burner and door openings. Tube ends may be welded together to obtain any length desired. Modern large furnaces have envelopes of virtually tangent tubes; i.e., no intervening refractory surface or backing.

Cast on, brazed on, and bolted on cast iron blocks have been used to obtain extended water cooling and to resist coal or ash erosion in applications such as stoker clinker chills. Because of differential expansion between blocks and tubes it is difficult to maintain the intimate contact without which the blocks will overheat and burn. For this reason cast iron blocks have been superseded for this purpose by heavy offset fins welded approximately in the plane of the face of the tube.

Construction of the furnace walls behind the furnace tubes differs widely depending on the size and spacing of the tubes, and the furnace design. Widely spaced tubes may be backed by a conventional wall of standard firebrick shapes. Walls of more closely spaced tubes may, alternatively, be made of semi-encircling or T tile or cast refractory which in turn is backed by standard brick shapes or insulation.

Tangent tubes require no refractory backing but may have an inner casing plate welded to them to assure gas tightness. Since its temperature is about that of saturated steam, only an insulating backing need be used behind this casing.

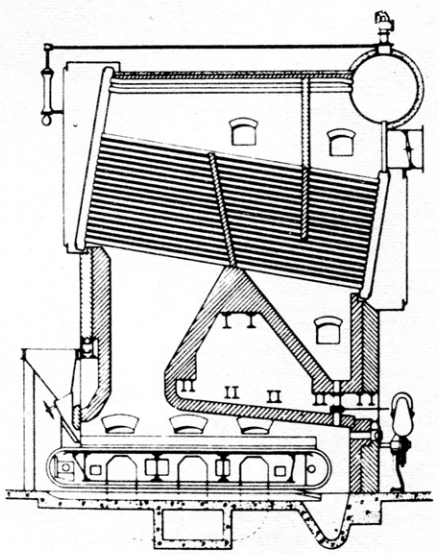
Unrestricted circulation of steam and water is requisite to all furnace water cooling designs as in some areas the heat absorption may be as high as 200,000 Btu/sq. ft. hr. of projected surface. More about this under Circulation. Internal surfaces must also be kept scrupulously clean. Even with clean tubes, the furnace side of water wall tubes may reach a temperature 50 to 75°F above saturation temperature.

REFRACTORIES AND INSULATION

The temperature to which a furnace wall is subjected lies between that of the flame inside and the ambient outside, and except where shaded by water cooled surfaces will be nearer the former. Materials which will withstand furnace temperatures are known as refractories and are usually composed of vitrified mixtures of metallic oxides such as silica, magnesia, alumina, and chrome. These are molded into standard and special firebrick shapes. They vary somewhat in fusion temperature (2700° to 3700°F), mechanical strength, and co-efficient of expansion.

Except when special high temperature cements are used, firebrick are laid with thin joints of only sufficient fireclay gruel to assure full support, as the brick are more resistant to deterioration than the bonding materials. Mechanical strength and co-efficient of expansion are important in large furnaces. Expansion joints are staggered and packed with a compressible material to exclude dust and slag which might otherwise prevent their functioning. Some furnace roofs are made of refractory tile suspended individually on hangers and grouted with fireclay.

The trend, however, is strongly toward the elimination of exposed refractory in boiler furnaces.



Old cross-drum box-header boiler fired by C-E Travelling Grate Stoker. Note suspended furnace arches and refractory walls.

Both plastic and castable refractories are commonly used in constructions which do not lend themselves to pre-formed tile, as well as for repairs. Plastic refractories such as chrome ore, are shipped in drums and used as packed. They must be molded or pounded into place. Castables vary in the proportion of their constituents. Depending on whether they are to be used in a hot or relatively cool location, they will be proportioned to take a strong hot or cold set. A hot setting or vitrifiable material will not set strongly until burned; it is usually held in place while cold by the adhesive qualities of raw clay which vitrifies at about 1800°F, molasses, lignin, or other organic binder. A cold setting castable to be used for a rear baffle, for example may depend principally on Portland or calcium aluminate (which sets hot or cold) cement for its strength. These materials are shipped dry, mixed before pouring with the correct amount of water, and cast in forms or in a confined space.

Gannister is crushed firebrick. It is used as a filler (grog, or bulk material) for some castables, or as a refractory to be poured into a confined space where no binder is required.

Firebrick fail by erosion at high temperature, by fluxing with ash, or by spalling. In general "hard burned" brick are resistant to high temperatures but tend to "spall" or flake off on the surface because of expansion strains resulting from temperature shock, as between joints. A light ash coating will tend to protect the brick, but hard slag and clinker accretions will likely take part of the brick with them when broken off.

• • •

The materials in common use as high temperature (600° - 1800°) insulating materials - and their suitabilities for different applications vary widely - are asbestos, 85% magnesia, rockwool, diatomaceous earth (raw and calcined), lime-silica, and pulverized coal fly ash. Like refractories, they may be preformed or plastic.

• • •

The outside face temperature of a furnace wall must be kept low enough to prevent serious discomfort or danger to the operators and to avoid high radiation loss. On the other hand, wall thickness beyond this requirement increases setting cost and raises inside wall face temperature, which may endanger exposed refractory.

It is usual to design walls for an outside temperature about 60° to 75°F above the ambient temperature. However, the wall face temperature will depend not only on furnace and ambient temperatures but also on air circulation and the surroundings. For example, of two walls of the same furnace, one adjacent to another operating boiler and the other to an outside building wall, the former will have the higher temperature.

Casing hot spots, when they occur, are caused by gas leakage and not heat transfer by conduction. A high draft differential across baffles conduces to leakage around them thru the setting. Door openings and soot blower wall boxes introduce sealing problems since they are subjected to expansion strains and may be required by their design to move relatively as the unit expands.

BOILERS

SIZE DESIGNATION

It is, of course, necessary to designate boiler size and rated output in some manner, and the basis first chosen related to the amount of steam required by engines then in use to produce a horsepower-hour of work. Subsequent minor refinement defined this as the equivalent of 34.5 lb. of steam per hour from water at 212°F to steam at the same temperature or approximately 33,500 Btu per hour. Boilers then in use would evaporate this amount of water with about ten square feet of heat-absorbing surface, so all power boilers were rated in terms of boiler horse-power, i.e., square feet of heat-absorbing surface divided by ten.

The term "per cent of boiler rating" meant total heat absorbed by the entire unit divided by the product of one-tenth the boiler (only) heat absorbing area and 34.5 X 970.2 (latent heat of vaporization at 212°F).

These terms are rarely used today. There is no longer a close relationship between the amount of steam required to produce a horsepower-hour in a prime mover and the area of the boiler - indeed, in large modern steam generating units only a small proportion of the total heat liberated is absorbed by the "boiler" itself.

Present practice is to describe industrial boilers in terms of their maximum continuous steam output in pounds per hour. This, it must be pointed out, only approximately describes the rate at which the unit absorbs heat. The capability of a large electric utility reheat boiler is often designated in megawatts corresponding to the output of the prime mover it serves because of re-use of the steam.

There is a trend toward describing steam generator capability in terms of heat output in millions of Btu/hr. (K Btu/hr.)

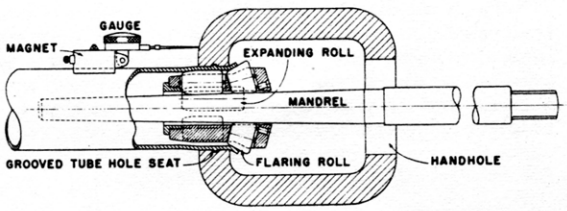
TYPES - CONSTRUCTION

Boilers are described as fire tube or water tube, depending on whether the water is outside or inside the tubes which comprise the principal part of their heat absorbing surfaces. There are also some shell-type and cast iron boilers, the latter used as low pressure heating units, which have no tubes.

Tubes and drums are used as the principal pressure parts largely because of their ease of manufacture and the characteristic of a cylinder that it has maximum strength for minimum material. Tubes can be bent readily and arranged in groups which give effective heat absorption and minimum cost.

Water tube boilers use tubes in the approximate size range $1\frac{1}{2}$" to 4", always designated by outside diameter. Fire tube boiler "flues" are sometimes as large as 5" or 6" in diameter.

Headers are used in waterwall construction to connect groups of tubes. They are usually formed of heavy wall tubing or pipe, but may be forged. Box headers and some boiler furnaces are formed of substantially parallel plates arranged to be mutually supporting by means of stay bolts or stay tubes.



Cross-section of square header showing tube expander and dial gauge in place. As the mandrel is turned it moves forward axially, forcing the rolls into firm contact with the tube seat. Elongation of the tube which indicates degree of expansion is shown on dial gauge secured to tube by magnet.

For operating pressures up to about 500 psig, tubes are joined to drums and headers by rolling. The metal of the tube is forced into firm contact with the seat by an expanding device consisting of a series of tapered rolls and mandrel. The metal of the tube is deformed plastically and hardened by cold working with the expander so that it is gripped firmly by the tube seat, which is not correspondingly deformed. Seats may be grooved to obtain a stronger seat. As the tube is rolled it is extended slightly; this extension may be measured by a dial gauge to indicate when the tube is sufficiently rolled. Tubes are "belled" in the same operation to assure that they will not pull out of the seat.

Higher pressure tubes may be rolled and seal welded. Alternatively, and invariably at the higher pressures, tubes are strength welded to terminal nipples which are welded to headers and drums at the factory before these parts are stress relieved. This construction requires fewer hand holes, thus reducing likelihood of leakage.

All structural requirements relating to strength (hence, safety) are described in the ASME Boiler Codes and State or other laws. These include such items as materials, permissible stresses, ligament efficiencies, methods of joining parts, welding techniques.

CIRCULATION

As can be observed in a pan of rapidly boiling water, the steam bubbles rise thru and disengage from the liquid, but the water level is higher than before ebullition started. Water is displaced by steam bubbles and since the volume of steam and water is greater than that of the water, the density of the mixture is less. This simulates the condition in a boiler drum. The effect is somewhat greater in a test tube if heat is applied to a larger area, since the disengaging surface is less. This somewhat simulates the condition in a boiler tube. (Except at very high pressure the change in specific volume of the water is inappreciable as compared to that resulting from the transition from water to steam.)

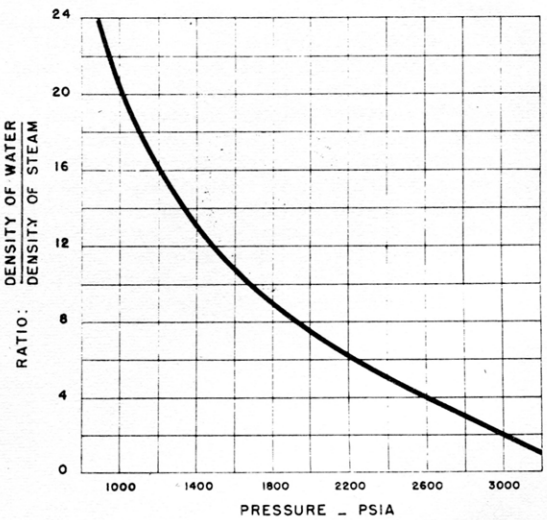


Chart showing ratio of water to steam density vs. pressure.

That the density of a steam and water mixture is appreciably less than that of solid water is evident from the fact that a water column connected to the drum to indicate water level, always reads lower than the level in an operating boiler.

This difference in density of the steam-water mixture in the highly heated part of a boiler as compared to the water in a cooler part of the circuit provides the circulating tendency in a natural circulation boiler. Flow is impeded, however, by the hydraulic resistance of the circuit (length of tubes, bends, entrance losses) and inertia.

Since frictional resistance is zero at no flow but increases rapidly with flow rate, the circulation ratio of a circuit, i.e., ratio of weight of water entering to weight of steam leaving, depends on both circuit "head" and resistance. Entrainment or generation of steam in tubes acting as downtakes tends to reduce net head.

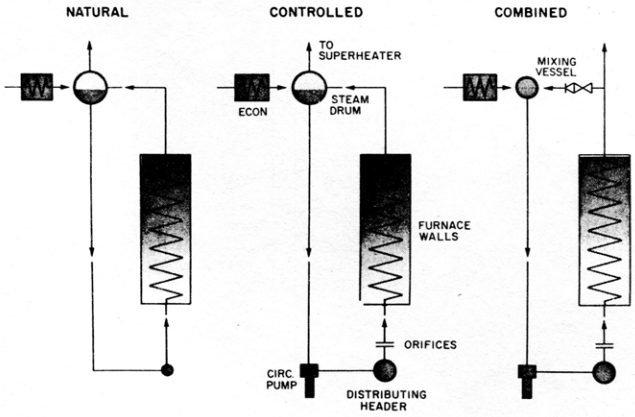
In a natural circulation boiler this circulation ratio will vary considerably in different circuits. It is not critical, but must be sufficient to assure continuously wetted internal surfaces and avoidance of local chemical deposits from evaporation.

The shading of a tube by slag or otherwise, particularly in the lower part of a circuit, may seriously impair circulation by reducing the amount of steam generated in that circuit.

The impetus to natural circulation falls off rapidly with increased operating pressures, since specific volume of the steam decreases rapidly. Comparing the density of water to that of a mixture of one part steam and three parts water by weight, we see that the ratio of these densities is 402 at atmospheric pressure, 63 at 100 psia, 5.9 at 1000 psia, only 1.8 at 2500 psia, and 1 at 3206 (critical pressure).

It is apparent that a pressure is reached where density difference is insufficient to assure circulation regardless of the height of the circuit, since system resistance will increase with length (hence, also height).

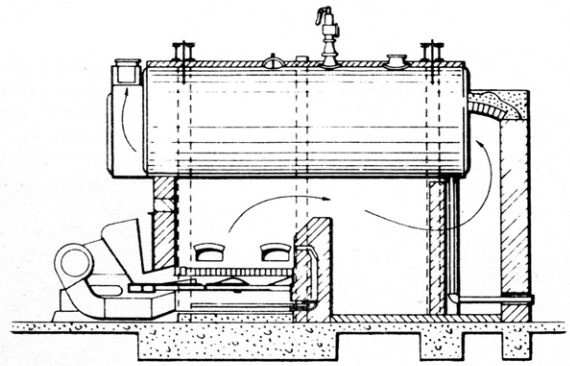
C-E CIRCULATION SYSTEMS



At this point some other mechanical means must be added to promote circulation. The provision of mechanical circulation has advantages other than the accommodation of a boiler to very high pressure operation, as will be discussed later.

FIRE TUBE BOILERS

A popular stationary fire tube boiler is the horizontal return tubular (HRT) in which the gas passes from the furnace under the cylindrical drum to the back of the boiler, then horizontally forward thru a series of tubes within the cylinder. Vertical fire tube boilers are used for small portable installations; locomotive, some marine, and several small automatic boilers are also of the fire tube type. Fire tube boilers for stationary use are usually not larger than 300hp, i.e., 3000 sq. ft. heat absorbing surface.



Horizontal Return Tubular Boiler fired by C-E Type E Stoker. (Arrows indicate direction of gas flow.)

In general these boilers have an advantage in low first cost, simplicity, free circulation, and low draft loss for the applications in which they are used. However, the exposure to high temperature of the part of a boiler in which precipitated solids from the boiler water tend to collect is potentially hazardous.

WATER TUBE BOILERS

Water tube boilers are of two general types, straight tube and bent tube (or drum type). Drum and header arrangements are combined in some designs, usually to provide partial furnace wall protection.

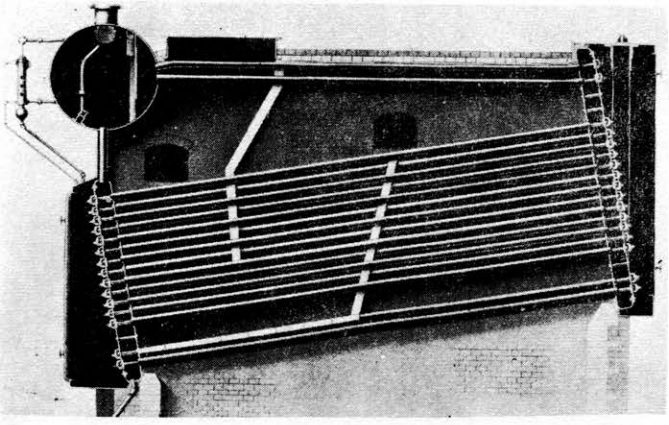
As the rate of heat transfer from gas to tube depends among other things on the film thickness or boundary layer resistance, turbulent flow, hence high gas velocity, is desirable. However, high gas velocity increases draft loss and may promote cinder erosion. Tube and baffle arrangements are designed with these considerations in mind. Access for cleaning and repairs must also be considered. Cross baffling of straight tube boilers, for example, improves heat transfer, but at the expense of draft loss and accessibility.

STRAIGHT TUBE BOILERS

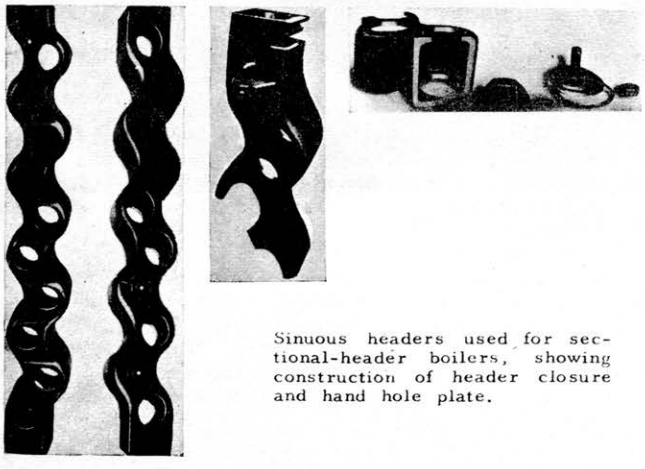
Straight tube boilers have vertical or slightly inclined headers into which the tubes which constitute the heat absorbing surface are connected. Headers are of two general types: box and sectional. Box headers consist essentially of two large plates welded or riveted to closing plates at their edges, supported by staybolts or stay tubes at required intervals. Tube holes are drilled in one plate and hand holes in the plate opposite.

Sectional header boilers are made in "sections" usually one tube wide except for clusters of small tubes. The headers to which the tubes are connected are often forged to a sinuous shape to permit staggering the tubes.

In cross drum boilers of both box and sectional header types the drum is located above the rear (low) headers and connected to both front and rear headers by steam and water circulating tubes.



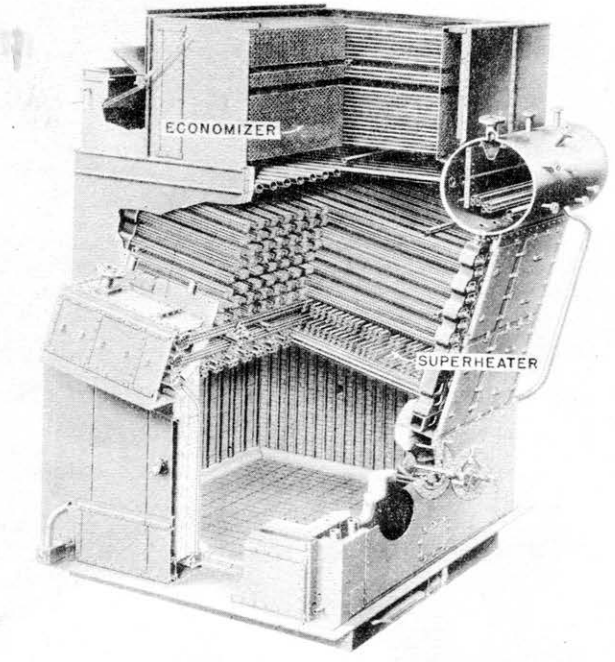
A cross-drum C-E Heine Box Header Boiler.



Sinuous headers used for sectional-header boilers, showing construction of header closure and hand hole plate.

Some box header and a few sectional header boilers have been made with longitudinal drums connected to the headers by circulating tubes, or, in the case of box header boilers, by extending the headers to throats which are connected directly to the drum shell. To provide for drainage and blow down of precipitated solids, sectional header boilers have mud drums (transverse headers) located under the low end vertical headers and connected to them by tube nipples.

Straight tube boilers have the advantage over bent tube boilers that all tube bank tubes are plain, identical, and can be withdrawn thru handholes without disturbing other tubes. A tube cleaner will pass thru them readily and to some extent visual inspection is possible. Straight tube boilers usually require less head room than bent tube boilers for the same heating surface. Circulation is not as positive and active, however, as in the bent tube type, and some trouble has been experienced in high tube banks because of inadequate or reversed circulation at high steaming rates. Straight tube boilers usually weigh (hence, cost) more than comparable bent tube boilers. Their application is now generally limited to marine or other use where height is a limiting factor.



C-E Single Pass Sectional Header Marine Boiler. Note horizontal superheater; also economizer.

BENT TUBE BOILERS

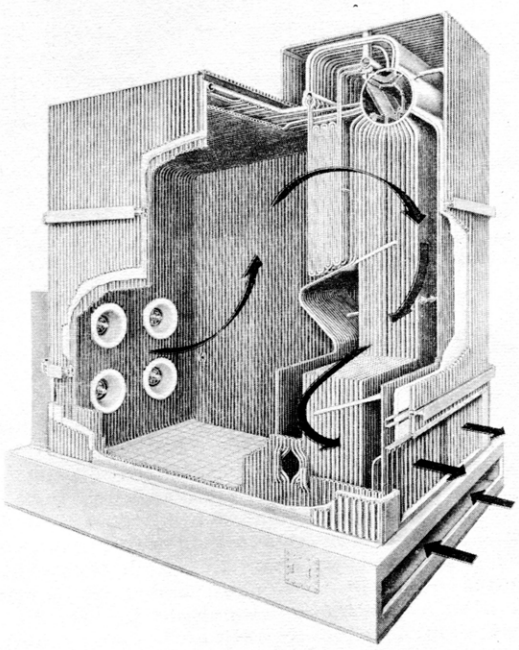
As contrasted to straight tube boilers, bent tube boilers have superior circulation characteristics which suit them better to high evaporation rates. In general, the design is more versatile and less costly.

Customarily, bent tube boilers are arranged with one lower ("mud") drum (except for double set or integral economizer boilers) and one or more upper drums. Early designs usually used multiple drums and "serial separation" of steam and water. Tube patterns were sometimes staggered to increase ligament dimensions and permit thinner drum shells. Improved drum internals now permit and cost favors single upper drum arrangements. Welding of drum shells permits the easy use of different plate thicknesses without the complications of the earlier riveted construction. Drums are costly and economy favors the fewest number which can accommodate the required tubes.

The tubes which constitute the bank of a bent

tube boiler are always arranged in rows in both directions, and are often spaced to permit the withdrawal of a tube thru the bank. Cleaning by soot blower jets also argues for open lanes except where the jets blow parallel to the tubes. Closely spaced tubes in the rear section of such boilers may not be individually accessible for replacement. However, gas temperature at this point is comparatively low and if a leak occurs, the tube ends may be plugged without danger. Gas flow may be across or parallel to the tubes.

Internal cleaning is no longer a problem limiting bent tube design. Bent tubes may be cleaned by articulated turbine driven cleaners or by chemical means. Improved water treatment often eliminates the need or greatly reduces the frequency of cleaning required.



C-E Type VU-60 Steam Generator

FORCED CIRCULATION

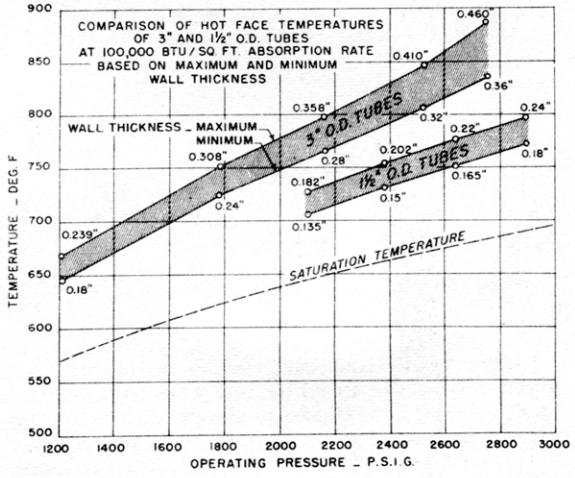
The provision of external mechanical circulation impetus (forced circulation) to a boiler removes the design limitations imposed by natural circulation. Such circulation impetus may be provided by a circulating pump ("controlled" circulation) or by use of the feed pump in a once-through boiler.

Both designs are described briefly.

CONTROLLED CIRCULATION

Altho in practice the arrangement of heating surface in large controlled circulation power boilers generally simulates natural circulation design, there need be no concern over "starved" circuits, and great flexibility in arrangement is possible. A large number of parallel circuits may be used with the knowledge that the resistance, hence flow rate, may be adjusted as desired by orifices of correct size, and the assurance that there can be no temporary interruption of flow due to local suspension of natural circulation tendency.

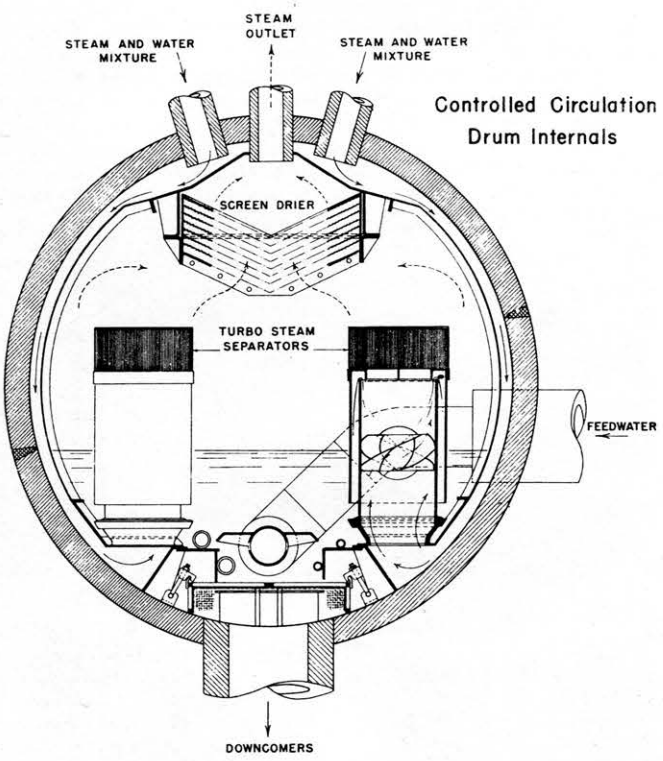
Tubes of small diameter (about $1\frac{1}{2}$" O.D.) are suited to this design. They have much thinner walls for a given pressure, hence lower metal temperature for the same pressure and heat transfer rate, greater flow turbulence, may be bent to close radius to form sidewall protecting panels. They weigh substantially less for the same heat absorbing area.



Because of the small tubes, the water content of a controlled circulation boiler is much less than that of a comparable natural circulation boiler, but the positive circulation minimizes the water level variation which accompanies rapid load change. Violence of the explosion resulting from tube rupture is greatly reduced by the high circuit resistance which minimizes leakage. Indeed, controlled circulation boilers have remained in service for several days with leaks which would have required immediately shutting down a natural circulation boiler.

There are also advantages in drum location and design. Cylindrical baffles within the drum circulate steam and water in contact with the entire circumference of the drum shell, and since this circulation is practically independent of load, the drum metal temperature follows water temperature closely as the boiler is put into or removed from service. Variation in metal temperature at different parts of the drum no longer limits the rate at which a unit can be heated or cooled. This greatly expedites load pick-up as well as emergency repairs.

The design of drum internals for the separation of steam and water is not subject to limitation by pressure drop, and this permits the use of more effective separation devices.



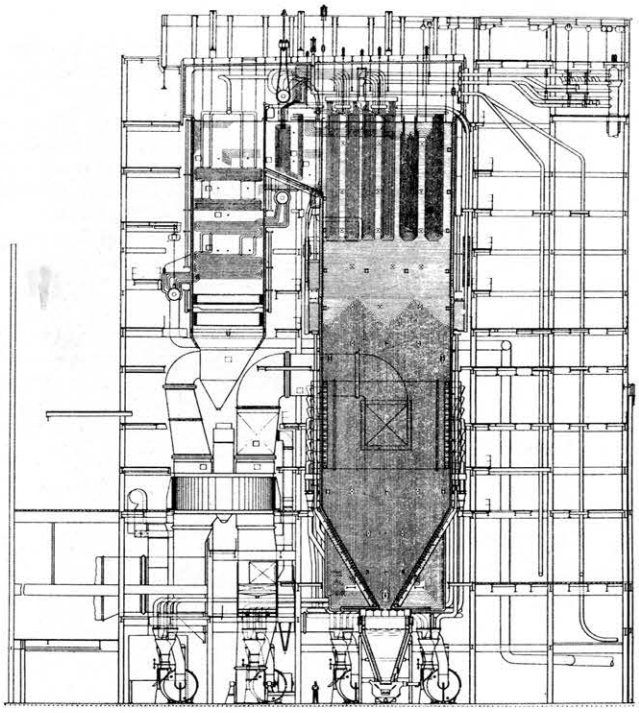
Drum internals design for Controlled Circulation Boiler.

The controlled circulation boiler also enjoys a great advantage in some low pressure applications such as waste heat and package boilers. The heating surface can be accommodated to congested locations without the need for high head to induce circulation.

The high availability record of controlled circulation boilers is no doubt the most important advantage to public utilities. Reduction in building size and support steel can often be evaluated in favor of the controlled circulation design, but the cost of circulating pumps, including a spare offsets the cost advantage of the lighter boiler weight when considering the unit itself.

Like all operating machinery, circulating pumps increase auxiliary power consumption and require occasional attention. Controls are provided to shut down the boiler in the event of loss of pump differential, a safeguard against damage from low water. (Power or mechanical failure may also cause loss of differential).

Altho operating against a low differential, circulating pumps must be sealed against boiler pressure. Packing gland seals require a labyrinth break-down to a low pressure, but to avoid packing damage from hot boiler water, clean cool water is injected on the pump side of the labyrinth. Inward leakage of this very small amount of water reduces efficiency slightly since it does not pass thru all feed heaters or the economizer, and injection water is not under control as feed water. Submerged pumps, either canned or wet motor type, are sealed, but are expensive.



Sectional side elevation of a C-E Sulzer Monotube Steam Generator. This unit produces steam at 5300 psig and 1200 F, with two stages of reheat at 1050 F.

ONCE-THROUGH (MONOTUBE)

In boilers designed for operation at supercritical pressures (above 3206 psia) there can be no circulation in the sense that steam disengages from water, with the water recirculating thru heat absorbing tubes. As heat is applied at constant pressure there is continuous increase in temperature of the fluid, and no point at which temperature remains constant with continued heat input. There is also a continuous increase in specific volume. There is no clearly defined boundary between the liquid and vapor phase, but there is a transition zone in which the volume increases more rapidly and the temperature more slowly. The fluid remains homogeneous with no boiling during this transition.

Supercritical boilers must therefore be of the once through type, in which water enters the boilers at one end of a number of parallel paths and emerges at the outlet as superheated steam. Movement of the water is "forced" by the boiler feed pump.

Subcritical boilers may also use the once-through design, incorporating steam and water separation and the removal of a small amount (about 5%) of the water to permit blowdown of concentrated solids.

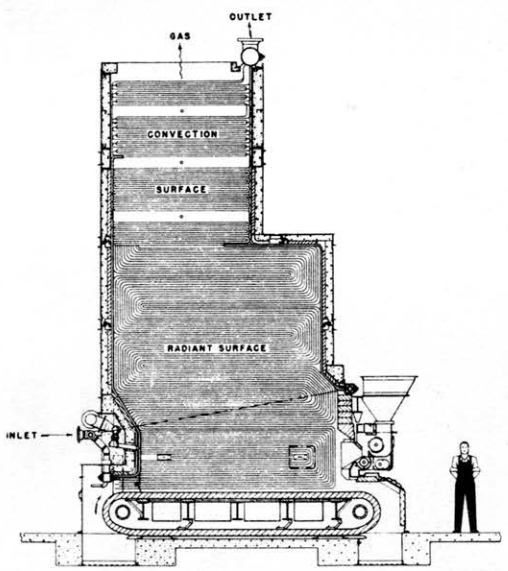
The C-E Sulzer Monotube Steam Generator employs these principles. The name derives from the feature of using continuous tubes from the inlet to the outlet of the evaporating section. This avoids the distribution problem inherent in a design employing intermediate headers.

A principle advantage of the once-through boiler is that it does not require circulating pumps or drums. Energy required for circulation is provided by the feed pump. The design is well suited to quick starts and rapid load changes since it utilizes small diameter tubes, has no drum, and provides positive circulation under all operating conditions. It is also adapted to the use of radiant superheaters because this surface is always protected by flow during start up.

The principle disadvantage is the requirement of extremely pure boiler water, about .1 ppm TDS in the super-critical design, since all solids present must be deposited in the tubes or carried along with the steam as dust. In the subcritical pressure range the limitation is slightly less severe, since there is some blowdown of boiler water.

HOT WATER "BOILERS"

A recent innovation in boiler design is the Controlled Circulation Hot Water Boiler. Its application is restricted to heating loads, altho by means of a heat exchanger low pressure steam could be generated at some point remote from the boiler, if desired.



C-E LaMont Controlled Circulation Hot Water Boiler. Erection view shows tube panels in place and C-E Continuous Discharge Spreader Stoker partly assembled.

Advantages of the system design derive from the fact that for a given volume, water contains more heat units than steam at the same pressure and temperature. Circulation thru the panels of boiler tubes and thru the heating system is entirely controlled by pumps.

High temperature hot water boilers are designed for pressures up to about 500 psig, corresponding to a saturation temperature of about 470°F.

DRUM SIZES AND SUPPORTS

In general, drum diameters are determined by considerations of strength (ligament efficiency) or steam releasing volume. Submerged drums are usually made as small as consistent with the insertion of all the tubes required. In some cases access for rolling sets the minimum size at 36" diameter. However, ingenious devices with extension drives may be used for rolling, or tubes may be welded to shop-welded stub tubes.

Steam drums are usually larger than submerged drums to provide space for separation of steam and moisture - up to about 70" in diameter. Low pressure boilers require larger steam drums than high pressure boilers for the same steam delivery per foot of drum length because of the greater specific volume of the steam.

The length of the steam drum(s) is determined by steam liberation rate (considering the diameter also) and the method of supporting the boiler.

Most water tube boilers of large size are supported by the upper drums, either in chairs or U-bolts. Furnace tubes and headers, superheaters, and other heat absorbing tubes are supported by hangers from overhead steel. Smaller boilers are often supported by chairs under the lower drums and supports under the lower furnace headers. In some designs the furnace walls are supported at about mid-height to minimize movement from expansion.

Box header boilers are supported by lugs on the sides of the headers. Sectional header boilers have the front end of the sections hung from lugs on the top of the headers or from U-bolts around the steam circulators. Marine boilers are usually supported by their casings.

In all cases, the design of boiler and furnace (as well as piping) supports must take cognizance of expansion due to considerable temperature variation. The bottom of a large steam generating unit may move downward several inches in going from cold to operating condition.

DRUM INTERNALS

Drum internals have for their purposes: (1) Cleaning and drying of the steam, (2) distribution of feedwater, (3) provision for maximum effectiveness of deconcentrating blowdowns, (4) protection of the structure.

(1) Clean steam is important because modern turbines operate at high rates for long periods, and it is essential from the standpoint of safety to these prime movers as well as to maintenance of their efficiency and capacity, that the blades remain clean. Deposits, however, are selective. Superheater tubing may overheat if solids are deposited in it, and valves may become fouled.

Since solids in steam are carried by the moisture associated with it, steam purification (as to

solids, not gases) is primarily a matter of moisture removal. Modern power boilers deliver steam containing less than one part impurities per million. This is truly remarkable, since boiler water concentrations may run from a few to thousands of parts per million.

It is interesting to note that steam is probably the purest substance produced commercially - purer than 99.9999 per cent. Commercially distilled water would be intolerably dirty as steam.

While drum size has an important bearing on steam purity, internal baffling is even more effective. All such baffles are designed to use gravity, centrifugal force, and inertia to accomplish separation. Preliminary separation of water from steam is obtained by the manner in which the mixture is delivered from the tubes to the drum, and by baffles which change direction of flow. Since foam promotes carry-over, baffles which direct the water toward a foam blanket to beat down minute bubbles have been used. A secondary separator may remove most of the entrained moisture, after which the steam passes thru a drier. In general, separation improves with pressure drop. The controlled circulation boiler has an advantage here, since a larger drop thru the separator can be tolerated.

Driers usually consist of several layers of screen or closely spaced undulated plates. They permit passage of steam without much resistance while offering a large area on which droplets may deposit.

(2) Boilers which are fed thru a single nozzle, as contrasted to a series of tubes from an economizer, require an internal pipe or trough to distribute the feed water uniformly lengthwise of the drum. Feedwater is somewhat (and may be considerably) cooler than boiler water. It is usually discharged above the water level to avoid temperature shock to the structure. Distribution is important to obtain the uniform mixing which is desirable to avoid turbulence and promote residual internal feed treatment.

(3) Boiler blowdowns have as their purpose deconcentration and the removal of precipitated solids. The former may be continuous rather than intermittent; dissolved solids are then removed with a small amount of concentrated boiler water at the rate at which they enter with large amounts of feedwater. To achieve maximum effectiveness, deconcentrating blowdowns should be located where boiler water concentration is highest - removed from the likelihood of entraining steam or blowing down feed water.

Sludge blowdowns - which also deconcentrate - may be located at the bottom of a feed trough to remove sludge which forms when the feedwater reaches boiler temperature or comes in contact with boiler water. Alternatively they may be located at the bottom of a lower drum where gravity and quiescence concentrate sludge. Sludge blowdowns are not very effective, the water disturbance extending only a few inches from the inlet. Effectiveness may be improved by inverted angles or a baffle which will extend the disturbance a greater distance.

(4) Protection of the structure generally implies the avoidance of severe temperature shock. Feedwater distribution has been mentioned. Other examples are internal feed nozzle sleeves, and the circumferential baffle in controlled circulation boilers which directs circulating steam and water thru an annulus and in contact with the drum.

SUPERHEATERS

DESIGN AND LOCATION

The purpose of a superheater is to raise the temperature of the steam generated by the boiler to some point above saturation. The thermodynamic advantage of superheating steam can readily be seen by referring to the Total Heat - Entropy diagram, comparing the available heat above a given exhaust condition to the total heat in the steam, i.e., the theoretical cycle efficiency. Another important objective of superheat is to minimize moisture in the last stages of a turbine (to about 12%) to avoid blade erosion.

Most superheaters are made of plain tubing of rather small diameter (1-1/4"-2") to maintain high steam velocity and sufficient pressure drop to insure good steam distribution in parallel circuits. Tubes are usually supported and aligned by welded attachments. Rolled and mechanical joints have been used in the past, but since the joints are subject to thermal shock, tend to leak. Welded joints have become general practice.

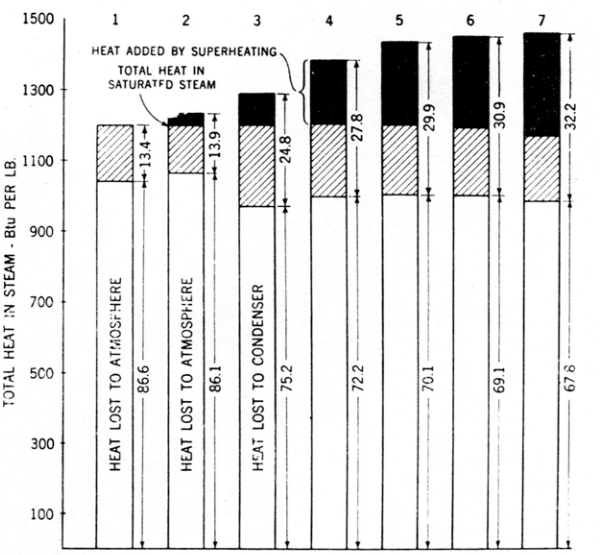
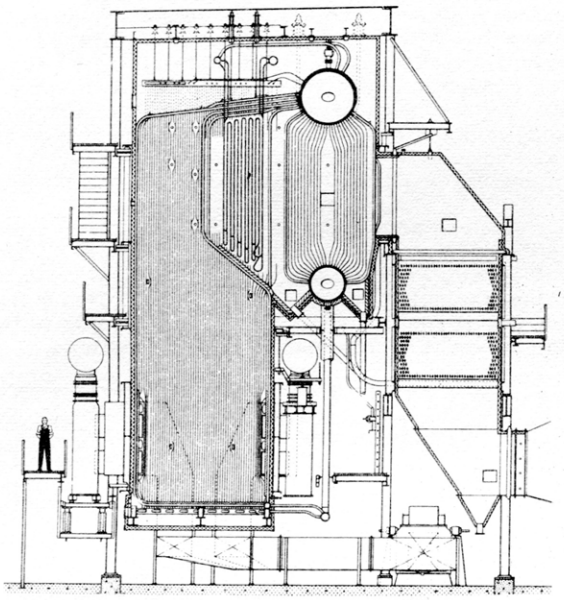


Chart illustrates improved prime-mover performance with increased superheat

Special applications may necessitate separately fired superheaters, but most are a part of the unit which generates the steam they superheat. Since the amount of tubing required depends on rate of heat absorption, the most economical superheater for a given performance would be placed close to the fire and have closely spaced tubes, but such a design would not operate with safe metal temperature, particularly when starting (before steam flow is established). Especially in industrial units, superheaters must often be adapted to conventional boiler designs.

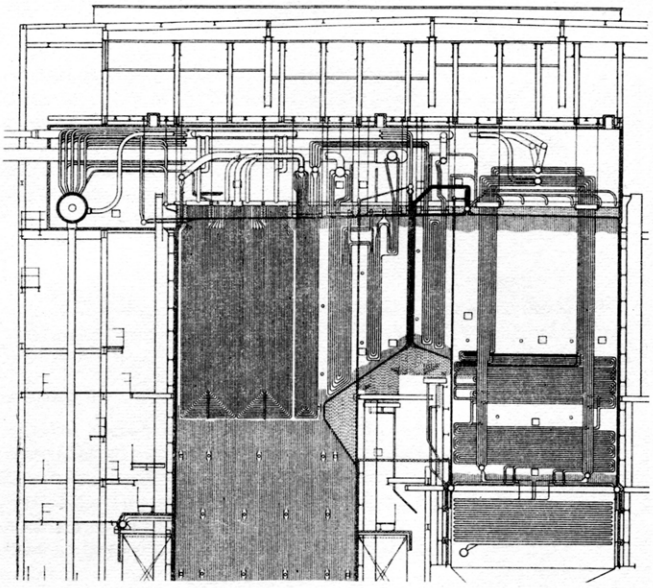


C-E Steam Generating Unit (CO boiler) to utilize heat in waste gas from catalyst regenerator. Note boiler and furnace tube arrangement to provide superheater space; also large economizer.

With straight tube boilers (box or sectional header) low temperature superheaters are usually placed horizontally above the tube bank (overdeck) in the first pass, with the headers behind the baffle at the top of the second pass. If higher steam temperature dictates a location nearer the furnace, part of the boiler tube bank is lowered to provide a space (interdeck) for the superheater.

In bent tube boilers pendant superheaters are usually used, either between tube banks (interbank) or between tubes of the front bank (intertube). Tube spacing in these locations is usually dictated by the slagging tendency of the ash in the fuel. The avoidance of serious obstruction to gas flow by slag-deposits has led to very wide spacing in some cases, and to the development of the platen superheater which absorbs a large part of its heat from radiation.

In steam generating units which include reheaters as well as superheaters, heat quantity and temperature head dictate the usual arrangement of two-stage superheater with reheater between. At locations where ash build-up is not a serious consideration, tubes may be closely spaced to utilize the improved heat transfer rate corresponding to the higher mass velocity.



Upper portion of 600 MW steam generating unit showing pendant and horizontal sections of superheater and reheater

As furnace temperature does not rise as rapidly as steam flow a radiant superheater has a falling temperature characteristic; that is, the steam temperature decreases as steam flow increases. A purely convection superheater has a rising characteristic; gas temperature and mass velocity increase with steam flow, the former at a more rapid rate.

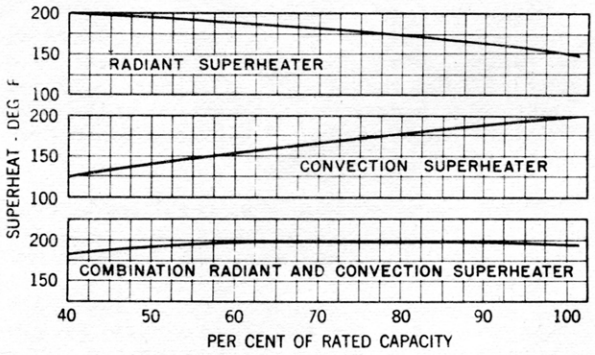


Illustration of typical performance characteristics of radiant, convection, and combination superheaters.

A convection superheater which "sees" or projects into the furnace combines these effects to some extent, tending toward a desirable flat temperature characteristic.

OPERATION

Since many superheaters are not drainable because of element design and header location, a cold unit with such a superheater must be fired slowly until condensate evaporates. Under start-up conditions the pressure drop is insufficient to blow water out of all tubes and those temporarily plugged with water may overheat at the top of the elements.

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Steam temperature will be influenced by any condition which affects steam flow or heat transfer; there is a slight lag due to the heat storage capacity of the metal and, in some cases, setting.

Decreasing excess air within the range where completion of combustion is not seriously affected will increase steam temperature from a radiant superheater (higher furnace temperature) and decrease that from a convection superheater (lower gas velocity) for the same combustion rate, and vice versa.

Changing the position of the flame by adjustment of burners or stoker may greatly affect steam temperature. A change in the type of fuel often has a very marked effect.

Slag deposits on the furnace or boiler tubes ahead of the superheater raise the gas temperature (hence, steam temperature) in the superheater zone. Slag or dust deposits on superheater tubes decrease steam temperature by increasing resistance to heat transfer.

Decreasing feed water temperature will increase steam temperature for the same steam flow because the additional heat added per pound of steam necessitates a higher firing rate. Also, the reheat outlet temperature will be affected by steam inlet temperature and weight of reheated steam.

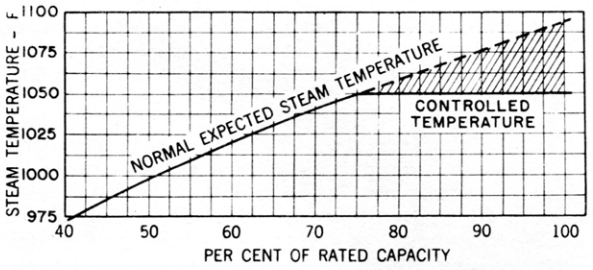
STEAM TEMPERATURE CONTROL

In many applications it is essential that the steam temperature be constant over a rather wide load range. Since the superheater cannot be designed for a flat characteristic, it must be proportioned to obtain desired temperature at the lowest point of the range or control point and controlled at higher loads.

Steam temperature may be regulated by changing the gas temperature or mass flow rate, or by removing part of the heat absorbed by the steam in the superheater.

An example of the former is control by tilting burners, which varies the effective furnace size and amount of heat absorbing surface with load changes. Response is immediate, and there is no hazard of steam contamination.

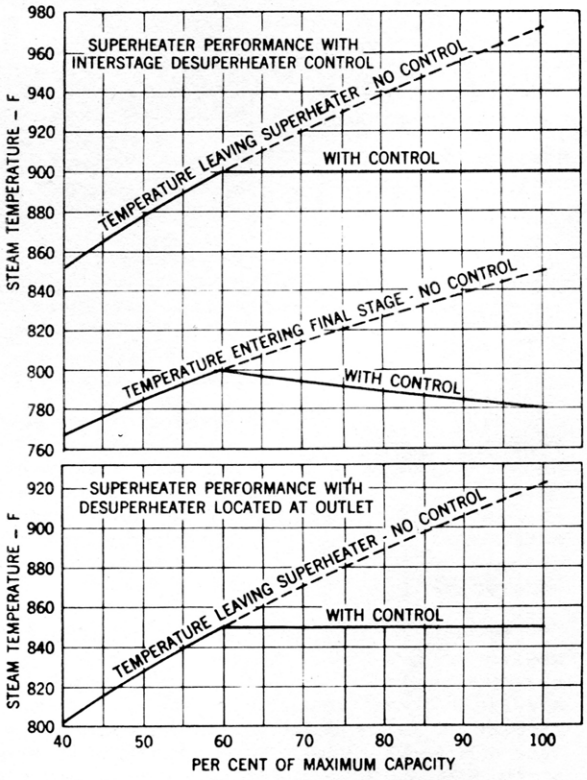
Steam temperature may also be controlled by by-passing part of the gas around the superheater at high loads. By-pass dampers are preferably located near the outlet of the unit to avoid exposure to high gas temperature.



Typical superheater performance with controlled steam temperature.

Recirculation may also be used; part of the gas is returned from the economizer outlet to the furnace. This lowers furnace temperature and furnace heat absorption while maintaining or increasing convection heat transfer by higher mass velocity and the greater amount of heat in the gas. It adds another fan to the system and increases auxiliary power not only because of this fan, but because of the increased draft loss due to greater gas weight.

A popular method of steam temperature control is desuperheating by water spray. Water is usually introduced between sections of the superheater to minimize outlet tubing temperature. Desuperheating water must have a purity comparable to that of the steam if contamination is to be avoided.



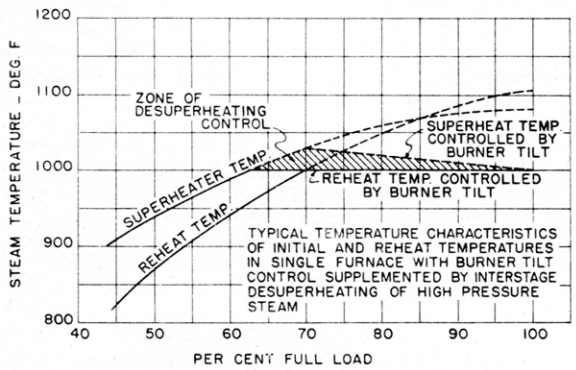
Performance with desuperheater control.

Two or more of these methods may be used in conjunction.

Marine boilers sometimes use a heat exchanger in the boiler drum to desuperheat steam used in auxiliaries designed for saturated steam.

While generally not acceptable as a means of steam temperature control, the operator has other temporary expedients: burner selection and adjustment, excess air regulation, selective de-slagging, and sometimes feed water temperature control. A substantial load drop, usually at night, will cool the furnace sufficiently to cause it to shed much of the slag. Use of some of these to adjust steam temperature may be opposed by other considerations.

Since the superheaters and reheaters cannot be designed and located so that their characteristics are similar, i.e., convection reheater characteristic slopes up more steeply, their temperatures must be individually controllable. In dual furnace units this can be done by locating the superheater in one and reheater in the other furnace with independent burner tilt controls. In single furnaces, desuperheating is necessary at some loads. Desuperheating reheated steam degrades the cycle slightly, so usual practice is to control reheat by burner tilt and control primary steam temperature by spraying as required at fractional loads.



Simultaneous control of initial and reheat steam temperatures.

MATERIALS

Maximum steam temperature so far proposed for power production is 1200°F, but 1100°F is about the highest in present high pressure use. The limitation is imposed chiefly by available turbine and superheater materials; the metallurgical problem is a very serious one, even at temperatures in current use.

Practice is to use carbon steel tubing (SA-192) for steam temperatures up to about 775 F; carbon steel with ½% molybdenum (SA-209 or T 1 b) up to about 875 F; 1¼% chrome ½% moly (SA-213, T11), or 2¼% chrome 1% moly (SA-213, T22) to about 1050 F, and, above that temperature, 9% chrome 1% moly or austenitic materials of the 18% chrome 8% nickel group (SA-213, TP304, TP341, TP347, TP316). Better alloys are being introduced but have not yet become standard materials. One, containing 17% chrome 14% nickel with lesser amounts of copper and moly, is good for 1200 - 1300 F range. Heat treatment in manufacture sometimes has an important bearing on suitability.

Since the tube metal temperature is the controlling consideration, (ASME code limits design stresses at various temperatures) a higher steam temperature may be used at lower pressure, as the tube wall is thinner and skin temperature lower. This is important (minor) with the austenitic steels, which have a lower conductivity than carbon steel.

For support material in hot locations the austenitic steels (cast or forged) are usually used at temperatures beyond the limit of carbon steel, the least expensive suitable material being selected. These are usually designed as welded attachments to minimize their temperature in operation. Best available material is a cast steel alloy containing about 25% chrome and 12% nickel, (or 25-12).

The principal problem with tube materials is to obtain high creep strength, i.e., resistance to deformation under constant load, but with support materials, corrosion resistance is more important.

Unfortunately, vanadium pentoxide and sulfur compounds, constituents of the ashy material from certain oils, severely attack these steel alloys at high temperature.

SECONDARY HEAT ABSORBING EQUIPMENT

While by no means a rule, economical boiler surface proportioning usually results in boiler exit gas temperatures about 200°F above saturation temperature at normal load. Particularly with high pressure boilers the provision of means to reclaim part of the heat in the exit gases is often economically justified, and in some cases is necessary (mill drying, for example) for satisfactory operation. Since sensible heat carrying capacity of the fuel is negligible, heat can be returned to the unit only in the boiler feedwater by means of an economizer, or in the combustion air by using an air heater.

Many factors influence the decision as to whether an economizer or air heater or both should be used. Air heater surface is usually the cheaper for a given heat recovery, but gas and air ducts, insulation, and possible building alterations may tip the economic balance. Circumstances sometimes justify installation of a common economizer or air heater serving two or more existing boilers.

If a plant operating cycle involves regenerative feed heating, this will limit heat recovery in (hence, applicability of) an economizer. Generally, an economizer should be proportioned to avoid steaming and possible water hammer.

Stoker firing usually limits air temperature to about 300°F and with a swinging load this may be dangerously high from the standpoint of damage to the grate, or adherence of tar or ash. Conversely, pulverized coal fired installations, particularly those using wet coal, require a much higher air temperature (600°F or above) to the mills.

Large high pressure, high-temperature boilers require both economizers and air heaters. Economics favor high efficiency, which means the lowest practical exit gas temperature.

Marine practice (which uses oil firing) sometimes reverses stationary regenerative cycle practice by bleeding the main turbine to preheat combustion air and recovering heat from the exit gases with an economizer. This has space and price advantages in ship-board installations.

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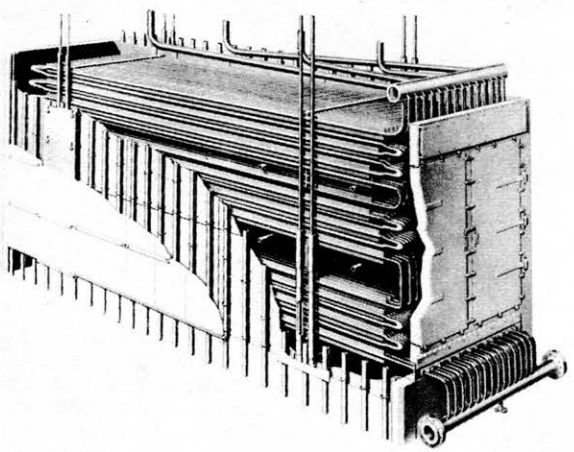
The reduction of exit gas temperature to a low value is attractive from an efficiency standpoint since recovery not only of sensible heat but of some latent heat of vaporization is possible. However, temperature is limited practically by the metal temperature at which condensation of vapors from the combustion products occurs. These condensed vapors contain sulfurous and sulfuric acid and are highly corrosive; they also act as a binder for ash particles, promoting deposit formation, altho in some instances larger fly ash particles tend to scrub the surface. The end products of the combustion of a given coal cannot be predicted accurately, so the exact dewpoint temperature cannot be forecast. The important consideration is not an average cold end metal temperature, but the minimum metal temperature under disadvantageous operating conditions, and the duration of these conditions. Corrosion resistant materials and short replaceable sections are sometimes used at the cold end of an air heater.



C-E Fin Tube Economizer.

Minimum metal surface temperature of an air heater may be raised by by-passing part of the air, thus reducing heat transfer rate from metal to air, or by recirculating part of the air, thus raising inlet air temperature. Recirculation has the thermodynamic advantage. The air may also be preheated somewhat in a steam air heater first.

Fouling of air heater and economizer surface is a serious problem and some means of cleaning is often provided in the design. Steam sootblowers are not too effective; since the deposits are acid, an alkaline wash with jets works better. Ljungstrom heaters may be made with removable basketed cold end surface to facilitate cleaning.

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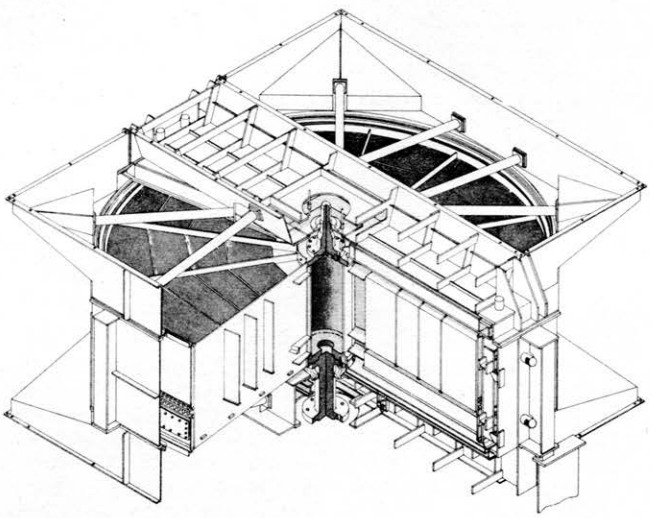
ECONOMIZERS

Economizers are usually made of steel tubes with extended surface - longitudinal fins or gill rings. The latter design (which has some disadvantage from the standpoint of fouling) usually uses corrosion-resistant material such as cast iron or aluminum. Economizers are vulnerable to oxygen corrosion because the feedwater passes thru them before entering the boiler. This may be combatted by recirculating some boiler water to raise the pH value, or by feeding an oxygen scavenger.

AIR HEATERS

Air heaters are of two general types, recuperative and regenerative. Tubular heaters are of the former and Ljungstrom of the latter type. Almost all are designed for counterflow to achieve greater mean temperature difference. Selection of type for a given installation depends on factors such as



Ljungstrom Air Preheater.

space, arrangement, and performance. In power boiler installation economics favor the largest possible air heater; such tubular heaters become very large indeed.

The Ljungstrom air heater, altho the more popular, has some disadvantage in its requirement of odd duct shapes (to accommodate considerable change in gas flow cross-section), the care of additional operating machinery, and maintenance of riding seals. However, up to the point of serious plugging, corrosion does not seriously affect performance. On the other hand, tubular heaters, altho very large, may be cased as part of the unit and may constitute part of the gas or air duct. While there are no moving parts, corrosion is serious. Not only do deposits inhibit heat flow, but a few holes resulting from tube corrosion may soon force a shutdown.

The tubular air heater (and Ljungstrom, if suitable allowance can be made for leakage) offers an easy rough check of (undesirable, since only part will enter the combustion reaction) air infiltration. Since specific heat of the air and gas is about the same, the ratio of gas temperature drop to air temperature rise roughly measures the percentage of air under control thru the air heater. A closer check can be had by considering also the weight of fuel in the gas, and the difference in specific heats.

RECOVERY UNITS

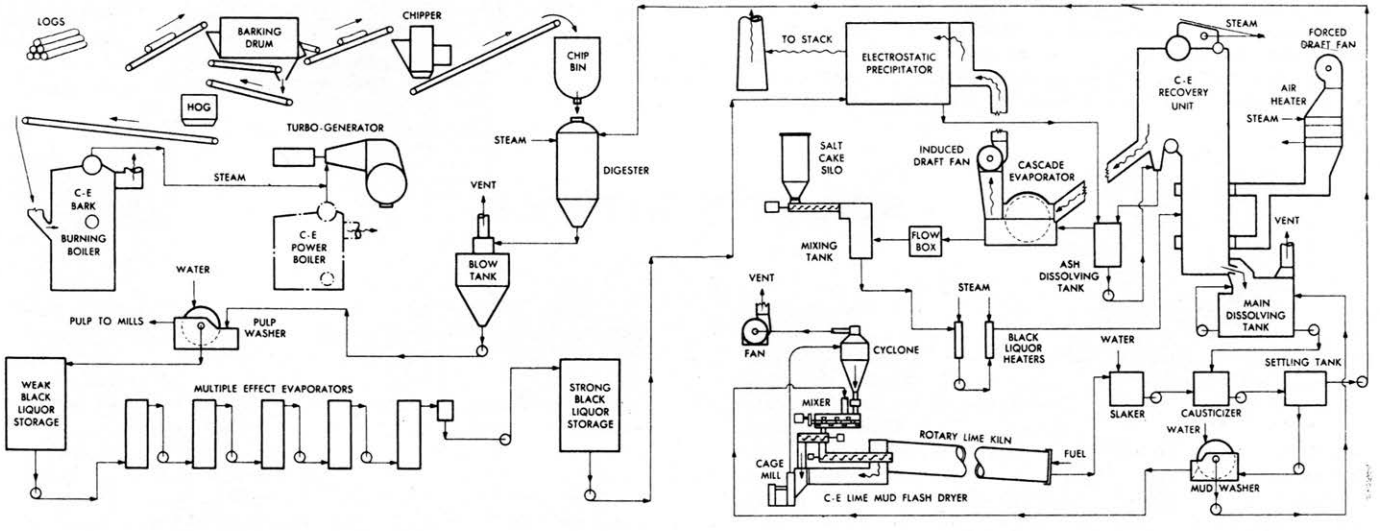
Among refuse fuels, black liquor warrants special mention because of its importance to steam generation in those pulp mills which utilize sodium base pulping processes. Mills of that type can be further classified as soda, sulphate, or sodium base sulphite depending on the composition of the cooking liquor. On the basis of production statistics it has been estimated that during 1957 20,000,000 tons of black liquor solids were produced and burned in the United States alone.

Logs for pulp manufacture are first stripped of bark, then reduced to small pieces by chippers. The bark, together with other wood refuse is usually burned in a specially designed steam generator. The chips are charged to the digestors together with the cooking liquor (sometimes referred to as white liquor) and cooked under steam pressure, usually 125 to 150 psig. During the digestion process, the lignins in the wood react with the cooking liquor while the fibrous cellulose portion remains essentially unchanged.

The fibrous portion of the wood is separated from the spent cooking liquor by filtering and washing, and is further refined for conversion into paper. The spent cooking liquor, now dark in color from liquor compounds, hence "black", is collected and concentrated from 12-16% to about 45-55% solids in multiple effect evaporators. It then passes to the recovery unit.

The recovery unit is essentially a device for recovering and processing certain chemicals which are used in the pulp making process; black liquor was burned to recover chemicals for many years before it was used to generate steam also. The value of chemicals recovered is (perhaps three times) greater than that of the steam generated, yet recovery units also generate a substantial amount, perhaps half, of the steam required for a pulp (not paper) mill.

Concentrated black liquor from the multiple effect evaporators first passes through the dust collector (usually an electrostatic precipitator) where it picks up the sodium compounds removed from the flue gas. It then enters the recovery unit at the ash dissolving tank, from which there is a controlled overflow into the cascade evaporator. Liquor from the ash dissolving tank is also recirculated thru the boiler ash hoppers to recover accu-



Flow diagram for pulp mill.

mulated ash. It is then further concentrated in the cascade evaporators by direct contact with the hot flue gas leaving the boiler. The gaseous effluent contains large quantities of water vapor, accounting for the characteristic white plume from the stack.

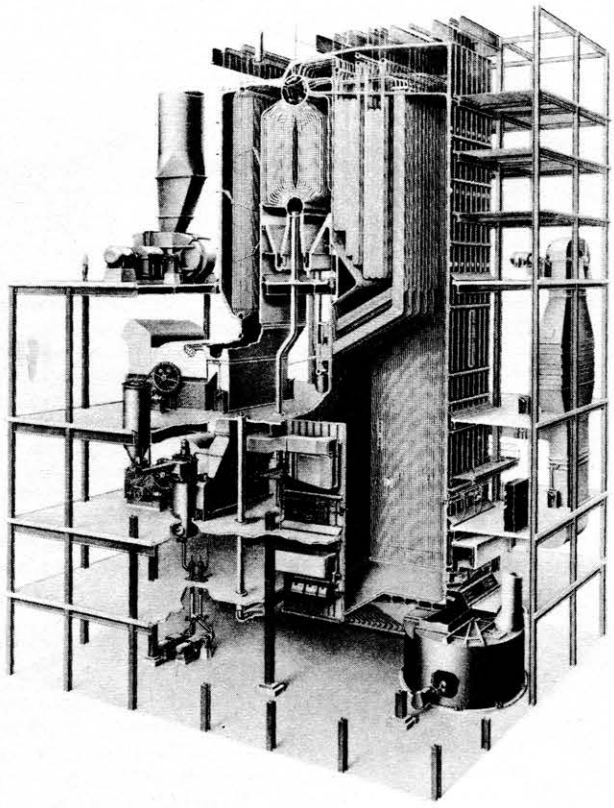
The heavy black liquor leaves the cascade evaporator thru a rotary screen in the flow box, and flows to the mixing tank where sodium sulphate (salt cake) may be added. It then flows by gravity thru the primary liquor heater to a centrifugal liquor feed pump and a secondary heater, thence to the spray nozzles.

Concentrated black liquor somewhat resembles heavy fuel oil in appearance and retains its fluidity only when hot. Burners of the oil atomizing type would, however, destroy the chemical recovery function of the furnace; therefore black liquor is sprayed into the furnace by guns which throw large globules of the substance. This "fuel" is about 35% water and 40% "ash".

Final drying is completed as the particles remain suspended momentarily in the hot turbulent stream of ascending combustion gas. The charred liquor particles settle to the bottom of the furnace where burning continues and smelting and reduction of sodium sulfate to sodium sulfide take place. The burning of the ligneous portion of the black liquor produces sufficient heat in the furnace to sustain flash drying of residual moisture, chemical reduction, and smelting. The heat in the gas passing thru the furnace, boiler, and economizer produces steam for power and process. Since chemical reactions which occur in the furnace are endothermic, the effectiveness of the furnace as a steam generator is related to the effectiveness of its chemical recovery and reduction functions.

Large quantities of ash are deposited as molten slag on heat absorbing surfaces, and some of the dust passes thru the unit. Deposits are removed periodically by soot blowers. Maintenance of a reducing atmosphere near the hearth and the release of some O_2 from the chemical result in a rather high CO_2 at the furnace outlet.

In general, the furnace and heat absorbing surfaces of a recovery unit resemble the proportions and arrangements used for other fuels. Some modification is necessary to accommodate the very large quantity and low melting point of the "ash", about 1400°F, and for the recovery of chemical dust



The C-E Recovery Unit has a flat, water-cooled decanting hearth and a completely water-cooled furnace, which assure low maintenance. A secondary tangential air system provides furnace turbulence. The absence of baffles in the boiler and the widely spaced tangent-tube panels of the furnace screen and superheater permit access for cleaning by retractable blowers.

(analogous to fly ash). These units may be very large - to burn liquor resulting from the manufacture of 650 tons of pulp per day, and to generate steam at pressures and temperatures up to 1200 psi, 900°F at a rate of about 300,000 pounds per hour.

Molten chemical (smelt) is discharged continuously through smelt spouts to a dissolving tank containing water where it is quenched and goes into solution to form green liquor. In a separate operation the green liquor is causticized with calcium hydroxide to form sodium hydroxide which is the cooking liquor for the soda or sulphate pulp process. In the case of the sodium base sulphite process the causticizing operation is eliminated and the green liquor is given special treatment as required to satisfy the specific sulphite process employed.

BOILER CONTROLS

Traditionally, the control of boiler firing rate, both manual and automatic, has been based on operating pressure, and the control of boiler feed has been based on drum water level. Furnace draft is measured directly, and the impulse used to change a damper setting or fan speed. This seems simple enough, but in practice the interrelation may become complicated. The objectives are to meet load demand and maintain optimum efficiency; the latter necessitates continuous correlation of several factors with the prompt readjustment implied.

Simpler controls are of the positioning type which move dampers, speed changers, or similar devices to pre-determined positions in response to the controlling impulses. More complicated metering controls balance the result of the changes against the impulses, often with supplementing compensating devices intended to accelerate response, control more accurately, and avoid hunting. Balancing or totalizing these impulses may be done electrically or mechanically. Control drives may be electrical, mechanical, hydraulic, or pneumatic.

The initial impulse from variation in steam pressure may change fuel feed and perhaps air flow. Air flow may alternatively be controlled by fuel flow. It may be measured by gas pressure drop across part of the heating surface or air pressure drop thru some part of the forced draft system. Volumetric fuel feeding devices do not measure heat input consistently because of variations in fuel quality, and resistance to gas flow across a tube bank may vary with fouling; hence some compensation may be needed based on gas analysis to maintain optimum fuel-air ratio.

Except for pressurized furnaces (which have only a forced draft fan) furnace draft must be controlled within reasonable limits, usually aiming at about .15 in. wg as measured near the top of the furnace. The furnace controller may actuate either the forced or induced draft fan or damper; the air flow controller will then actuate (or supplement actuation of) the other.

Regulation of boiler feed water flow has an important bearing on "combustion" controls, because, particularly with a feed water temperature substantially below saturation, the rate of feed water flow temporarily affects boiler output and steam temperature. If, for example, a water level rise (swell) resulting from a suddenly increased load (hence, accompanied by reduced boiler pressure) were corrected by an uncompensated feed water controller, the feed water flow would initially change in the wrong direction. A surge of cool feed water might momentarily reduce steaming rate and further lower both pressure and drum level, the latter by collapse of steam bubbles. A compensating control on steam flow tending to relate feed to load as well as to water level could reduce this unbalance. A three element control which coordinates feed and steam flow while acting to maintain or correct water level is better.

The impulse for controlling steam temperature must come from continuous measurement of that temperature, but to avoid time lag, may be anticipated by a device measuring load change or gas flow.

A once-thru boiler has no drum and no measurable water level. In the monotube design, steam flow is used as an anticipating impulse. The final correction is made in accordance with temperature at an intermediate point in the unit. This temperature replaces the water level impulse used for drum type boilers, and also constitutes the first step in control of final steam temperature.

A characteristic of the development of boiler design and higher steam pressures imposed by improved cycles has been a trend toward less water content for a given steam generating capacity - fewer and smaller drums, and tubes of smaller diameter. This has increased the responsiveness of these units and has both permitted and required faster acting controls.

With a boiler-turbine-generator combination, conventional controls act sequentially on each unit from output to source. Thus a change in generator output requires a change in turbine throttle position, this in turn changes steam flow and hence pressure; the steam pressure change actuates fuel feed to the boiler. The new direct energy balance system controls fuel feed directly from generator output and is therefore more responsive. Turbine input pressure may then be controlled by the throttle valve, the pressure being permitted to vary with load if desired. This control is especially suited to the once-through boiler, which, because of its small water content will respond most quickly of all boiler designs.

The controls for all large boilers are arranged for remote manual operation from a control station. Manual operation may be necessary when starting, and desirable in certain other situations. It is also general practice to interlock controls sequentially for safety - so that, for example, an induced draft fan failure will immediately trip out forced draft fan, pulverizers and feeders. Time and/or temperature delay relays may also be provided to prevent restarting auxiliaries except when it is safe to do so.

WATER TREATMENT

Boiler water conditioning is rather involved and mention will be made here principally of the purposes of treatment. There are four main purposes:

(1) Prevention of scale deposits which may cause overheating of the boiler structure, or impede flow elsewhere in the system, (2) prevention of corrosion in the boiler or elsewhere in the system, usually from oxygen, (3) prevention of caustic embrittlement, and (4) reduction of moisture and solids carryover resulting from foaming and priming.

Natural waters contain dissolved or suspended impurities which may cause trouble in a boiler. Concentrations in fresh waters vary from about 30 to over 2,000 parts per million (ppm). Sea water varies with localities, but contains about 35,000 ppm dissolved solids, largely sodium chloride.

The principal scale forming materials are calcium and magnesium carbonates and sulfates, and, in less amount, silicon salts. Salts of sodium, potassium, aluminum, iron, and manganese may also be present, of both mineral and organic (decay) acids. Other impurities are sediment, turbidity, and micro-organisms, as well as dissolved gases.

(1) The carbonates and sulfates mentioned above constitute temporary and permanent hardness.

They have the characteristic of reacting with soap to form insoluble curds, inhibiting its detergent effect. Both precipitate as scales when heated, carbonate scale being softer and more nearly like a sludge than sulfate scale. Silica produces a very hard, complex, scale which is most difficult to remove. Other materials may increase the scale bulk by entrainment, may enter into the composition of complex scales, or may deposit as a sludge.

The removal of solid contaminants, externally or internally, is often accomplished by precipitation, which, except for the carbonates, requires chemical substitution. Substitution does not necessarily reduce total solids but the substitute is relatively harmless.

The lime-soda process is a common method. Calcium and magnesium bi-carbonates, which are highly soluble, precipitate as carbonates on heating at a rather low temperature; most would be precipitated under 200°F. Calcium hydroxide reduces calcium and magnesium bi-carbonates to the carbonates and magnesium hydroxide, and soda ash reduces the calcium and magnesium sulfates to the carbonates and sodium sulfate. Heating accelerates the process by hastening precipitation of the carbonates. Silica removal may be accomplished as part of the process by the addition of dolomitic lime or activated magnesia.

Substitution of sodium salts of high solubility, even at boiler operating temperature, for scale-forming impurities may be accomplished by zeolite bed cation exchange equipment. The regeneration of the zeolite bed requires only backwashing with sodium chloride solution.

Demineralization, with an effluent comparable in purity to distilled water, may be accomplished by an extension of this principal. A hydrogen cation exchanger will provide an effluent in which the salts have been converted to acids. An anion exchanger using an alkaline resin bed instead of the zeolite, will then remove the acid radicals. This is a very effective means of water purification, limited somewhat by cost and the fact that it does not completely remove silica.

Water may also be purified by distillation.

Since pre-treatments are never completely effective, supplemental internal treatment for residuals is usual. The most effective internal treatment includes sodium phosfate which reacts with calcium and magnesium carbonates and sulfates to form a sludge which is not scale forming and can be blown down. Phosfate is fed to the boiler separately from the feed water to avoid clogging the feed pipe due to the sludge which would otherwise form within it.

Organic dispersives are sometimes used to assist in keeping precipitates in sludge form such that they can be blown down.

To a limited extent, potassium salts are used instead of sodium salts in boiler water treatment because of their higher solubility.

(2) Corrosion may be caused by dissolved oxygen or CO_2 in the boiler water, excessively high alkalinity, dissociation of steam in contact with hot surfaces, and by acid water. Both oxygen and CO_2 are highly soluble in cold water; organic acids may be present from decaying organic matter. The gases can be removed in an open feedwater heater to a minimum oxygen content of about .005 ppm, as their solubility decreases as temperature rises. Residual oxygen is removed by a scavenger (reducing agent) in the boiler water, usually sodium sulfite or hydrazine.

Acid, and to some extent oxygen, attack can be inhibited by maintenance of a proper pH value. Pure water ionizes to produce hydrogen and hydroxyl ions. The degree of acidity or alkalinity is measured by its pH (the logarithm of the reciprocal of the hydrogen ion concentration in gram-mols per liter) in a series of numbers from 1 (highly acidic) to 14 (highly basic) of which 7 represents neutrality. Dissociation at high temperature and a safety factor suggest that pH be maintained at about 9-11, depending on operating pressure , as measured at room temperature.

Very high operating pressures dictate the need for high water purity and scrupulously clean steam. Unfortunately, pure water is an excellent solvent and will attack condenser tubes and other parts of the system. The products of pre-boiler corrosion may enter the boiler, forming deposits.

To buffer this attack, hydrazine is frequently used. It is volatile, hence does not increase dissolved solids, raises pH, and is an effective oxygen scavenger. Morpholine may also be used.

Some oxygen scavenger and an alkalinizer must be added to the water in an idle boiler and superheater also, and hydrazine serves both purposes. Idle boilers are sometimes pressurized to 3-5 psig with nitrogen to prevent inward leakage of air.

(3) Caustic embrittlement is manifested by intercrystalline cracking of steel under stress at locations of high caustic concentration, such as may result from evaporation. Principle inhibitor is sodium nitrate; however, sulfate also buffers the alkalinity.

Riveted drums are particularly vulnerable since caustic concentration may build up under a leaky butt strap or lap joint. Rolled tube joints may also suffer attack. Welded construction has eliminated the vulnerability of drums and reduced caustic embrittlement generally, altho welded joints are sometimes susceptible to other attack.

(4) It is recognized that the presence of contaminants will promote carry-over, and members of the American Boiler and Affiliated Industries base guarantees on stipulated limits. Total solids, alkalinity, and organic matter (including oil) are all important. Any substance which tends to support a foam film will greatly increase the tendency of moisture to carry over with the steam, either continuously in small quantities or intermittently in large quantities.

Measurement of solids in condensate and sometimes in boiler water is usually made by conductivity, after removing the electrolytic gases, CO_2 and NH_3, by boiling. Alternatively, they may be measured by titration and a correction applied to the conductivity. (In the low contamination range, con-

TABLE I. AMERICAN BOILER AND AFFILIATED INDUSTRIES LIMITS FOR BOILER WATER CONCENTRATIONS IN UNITS WITH A STEAM DRUM

PRESSURE AT OUTLET OF STEAM GENERATING UNIT LB PER SQ. IN.	TOTAL SOLIDS PPM	TOTAL ALKALINITY PPM	SUSPENDED SOLIDS PPM
0 - 300	3500	700	300
301 - 450	3000	600	250
451 - 600	2500	500	150
601 - 750	2000	400	100
751 - 900	1500	300	60
901 - 1000	1250	250	40
1001 - 1500	1000	200	20
1501 - 2000	750	150	10
2001 AND HIGHER	500	100	5

" The COMPANY shall not be responsible for carryover resulting from the presence of oil, grease or other foam inducing materials."

centration in ppm is about one half conductance in micro-mhos.)

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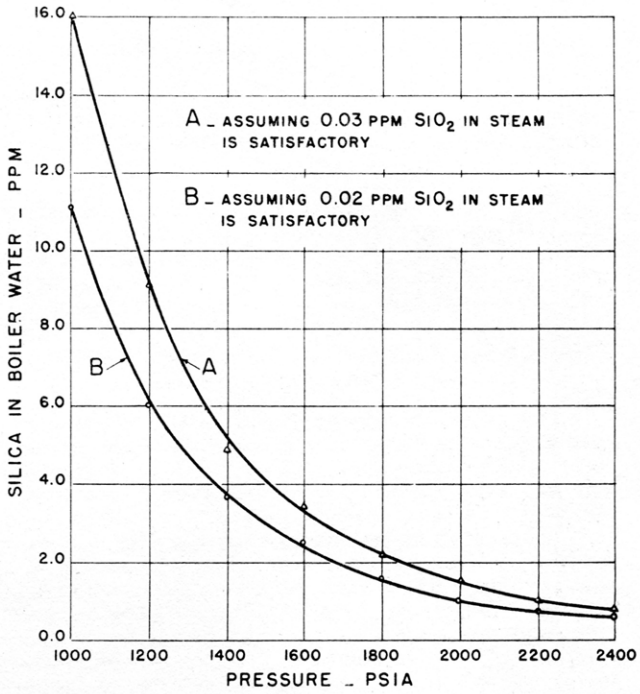
A number of "boiler compounds" are offered without much regard for the conditions to be treated. Like proprietary medicines, they may or may not cure, depending on the ailment.

Acceptable boiler water conditions vary widely with conditions, particularly operating pressure (hence, temperature). It takes judgment and knowledge to derive the least expensive procedure which will assure acceptable results, particularly in border line cases. A treatment to eliminate oxygen, for example, may involve sulfate or alkalinity control. The selection of a phosfate for residual hardness may also be related to pH control. Selection of an external feed treating system may be virtually dictated by silica removal. Silica, incidentally, usually determines the total boiler water solids permissible at high pressure since, in any but low concentration, (below 1ppm at 2500 psig) it will volatilize and condense in the turbine in troublesome amount. Operating cost or some chemical factor may dictate the choice between a demineralizer and distillation. Evaporator operation cost does not rise greatly with raw water concentration, but de-scaling the evaporators may be an operating problem.

ACID CLEANING

Inaccessibility for cleaning has sounded the death knell for many otherwise acceptable boiler designs. Even with modern boiler water standards and good control, scale formations sometimes occur. Safety of the structure more than operating efficiency require their prompt removal.



Allowable silica in boiler water at various steam pressures.

Economic factors, and, more recently, designs which are dictated by advantageous disposition of surface or assembly methods do not permit access for mechanical cleaning. Chemical cleaning of boilers is the solution. Some scales and metallic oxide deposits which cannot be removed mechanically, such as magnetic oxide from a new boiler, may yield to an acid wash. Siliceous scales are difficult to remove chemically and defy mechanical removal, but complex scales may sometimes be removed by the solution of their susceptible constituents.

For cleaning boilers - old and new - a weak solution of hydrochloric acid is usually used because it is inexpensive, easily available, and most of its salts are soluble. Fluorides (to attack silica) or other chemicals may also be used, as the composition of the scale suggests. Some substance is always added to inhibit metal attack.

Avoidance of structural damage and complete cleaning require careful control. Usually a solution temperature of about 160°F is used with an acid strength of 3-5%, for as short a period as possible consistent with scale removal. Occasional analysis of the solution indicates how the reaction is proceeding. There is some hazard involved from the liberation of hydrogen and hydrochloric acid vapor, necessitating careful venting of the boiler during the cleaning process.

The acid wash is followed by an alkaline rinse to neutralize acid and sometimes by a phosforic acid rinse to prevent oxidation of the newly exposed metal. The boiler may also be pressurized with nitrogen while out of service.

MISCELLANEOUS

A boiler designed for present low pressure at full load and eventual high pressure operation is rather expensive. Water wall riser tubes must be proportioned for the steam velocity at low pressure, and drum size must be selected for the greater low pressure volume, but built to the greater thickness corresponding to eventual pressure.

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The effect of increasing CO_2 (decreasing excess air) in the range in which combustion is complete in the furnace is to reduce both draft loss and exit gas temperature. Reduced excess air means higher flame temperature, hence increased radiant heat absorption in the furnace, as the differences of the fourth powers of the absolute temperature of gas and heat absorbing surface. Convection heat transfer (Btu/sq. ft. hr./°F temp. diff.) in a given tube bank varies as the one-half power of the mean absolute gas temperature and the three-fourths power of the mass flow rate. Increased furnace heat absorption and lower gas weight both tend to reduce exit gas temperature, therefore dry gas loss. However, an increased carbon loss may exceed the reduction in dry gas loss.

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Draft loss and gas pressure drop for a given system resistance vary approximately as the square of the mass velocity. "Mass velocity" or "mass flow rate" in pounds per square foot hour is more convenient to use than linear velocity since it does not change with temperature and is therefore constant through the unit, infiltration neglected. Except for wide ranges or changes in excess air, the rate of gas flow varies directly with steam delivery, hence draft loss varies about as the square of the load. This permits approximate prediction of draft losses from data at one condition.

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Design gas velocities are limited not only by excessive power consumption, but also in coal fired boilers by tube erosion caused by impingement of fly ash particles and, leaving the furnace, by adherence or "plastering" of plastic ash particles. Gas leaks thru baffles where a high draft differential exists, and concentrations of fly ash in the gas stream at vulnerable points may accelerate erosion.

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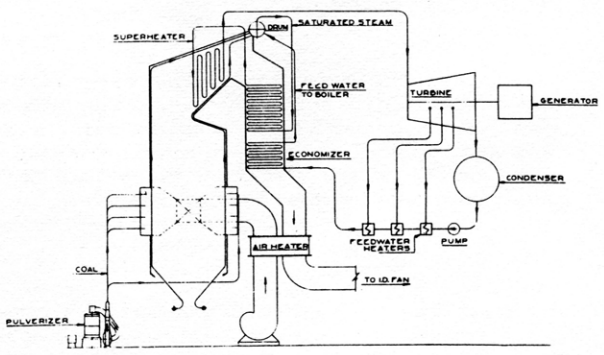
Reference to draft losses suggests the mention of the simpler fan laws, as they relate to boiler operation. It is sometimes useful to remember that for the same system resistance and a given fan size, the volume delivered by a fan varies as the first power of the speed, the pressure as the square, and the horsepower as the cube. With a change in density, pressure and horsepower vary directly, i.e., directly as pressure and inversely as absolute temperature, if speed (hence, volume) are constant. This has an interesting implication in connection with constant speed induced draft fans: when the fan is started and the steam generating unit is cold, the motor will overload if the damper is not partly closed. From the standpoint of protecting the motor from overload as well as maintenance of correct furnace draft conditions, care must be taken in adjusting induced draft fan dampers when starting a boiler.

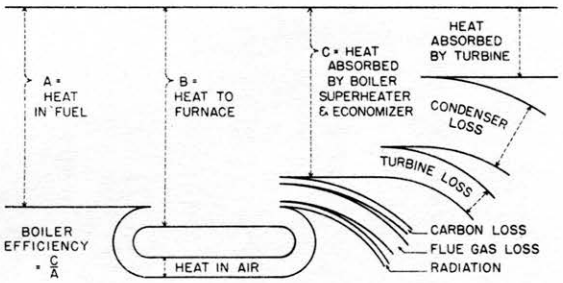
DESIGN OF POWER BOILERS

The practical and economic considerations governing the proportioning of steam generating units for power generation are interrelated. Major elements are pulverizers, burners, furnace, high temperature superheater, reheater, low temperature superheater (high pressure), economizer, air heater.

Economic considerations dictate that the largest possible air heater(s) be used consistent with a maximum metal temperature of 700°F, mechanical design considerations, and a gas outlet temperature as low as possible without risking serious trouble from corrosion and plugging. Recirculating some heated air or preheating the air in a steam air heater (to about 100 F) and good cleaning techniques may permit designing for an outlet gas temperature of 250 F or even lower, depending on the fuel. The pulverizers need air at a temperature of 550°F or higher to operate satisfactorily with high moisture coal. Equating heat absorbed by the air to that given up by the gas puts the temperature of the gas leaving the economizer and entering the air heater at about 600-650° F.



Diagrammatic layout of one steam power station.



Distribution of heat in fuel.

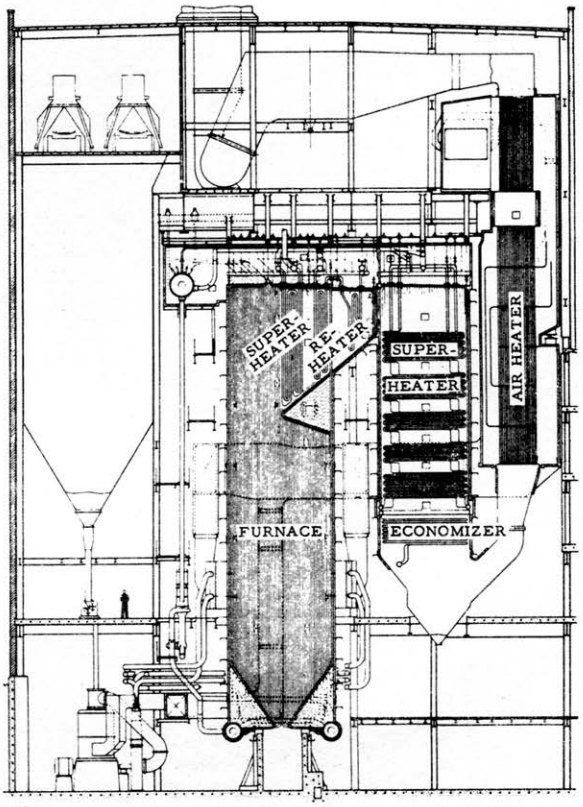
The furnace must be large enough for complete combustion with sufficient heat absorbing surface to reduce the gas temperature entering the superheater to the point, if possible, where the ash is no longer molten, (usually about 2000°F). Actually the required heat absorbing surface imposes the limit. Combustion products leaving the furnace must contain enough heat at a sufficiently high temperature to provide the desired superheat. In coal burning furnaces velocities must be limited to a point where fly ash erosion and slag accumulations due to lodgement of plastic or burning particles are minimized. These considerations are not entirely compatible in some units and initial superheater tubes must be exposed to furnace radiation. Avoidance of excessive slag formations is a major consideration in furnace proportioning.

Burners are placed so that they utilize full furnace size when tilted downward; much less when tilted upward. This permits steam temperature control over a wide load range, and distributes the deposits of slag over the walls. The lower part of the furnace is designed to shade ash removal devices without impeding their operation.

The furnaces of large steam generator units absorb about half the heat released (at high transfer rate, because of high temperature difference) so that the gas temperature leaving the furnace is about 2000°F.

The proportioning of the high temperature section of the superheater, reheater, low temperature section of the superheater, and economizer depend on the amount of heat to be absorbed by each, and the selection aims at minimum overall cost. Water cooled side walls and support tubes must also be considered. Excessive tube temperature must be avoided, as well as slag lodgement, fly ash cutting, and high draft loss. Small tubes spaced closely in a plane at right angles to the gas flow provide a high heat transfer rate at the expense of draft loss and possible plugging with ashy deposits. Reducing the size of the high temperature superheater will also permit reducing the reheater area because of higher gas temperature, but will require increasing the size of the low temperature section of the superheater. The overall superheater and reheater characteristics should be as nearly balanced as possible, and both should be designed to minimize the amount of high temperature tubing required.

Saturation temperature at high (but sub-critical) pressure may be in excess of 650°F and gas



Cross-section of reheat steam generator for 1,050,000 lbs/hr. primary steam at 1050°F, and 910,000 lbs/hr. reheat steam at 400 psig and 1000°F. Overall efficiency: 89.33%, Exit gas temp., 275°F, temp. feedwater to economizer, 500°F., Temperature control range, 700,000 to 1,050,000 lbs/hr.

Tabulation of heating surfaces, square feet:

Furnace	43,640
Superheater	113,182
Reheater	14,439
Economizer	42,430
Air preheater	317,500

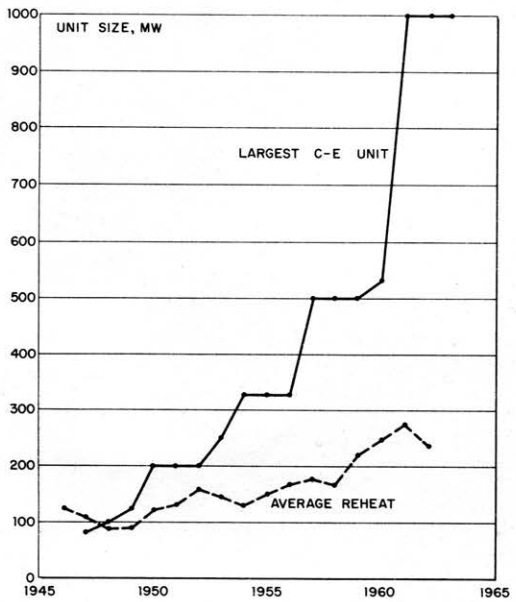
temperature leaving the low temperature superheater will be one to three hundred degrees higher. The economizer must absorb the heat represented by the difference in gas temperature at this point and at the air heater inlet. It can be seen that the economizer size affects and is affected by the extent to which the feed water is heated regeneratively by bleeding steam from the turbine, since the latter determines the amount of heat the economizer can absorb, as well as the temperature head.

Varying somewhat with the fuel analysis, a steam generating unit of this type will have a thermal efficiency of about 90% based on the higher heating value of the fuel.

Pulverizers are usually selected to permit operation without load reduction when one is out of service, as may be required for replacement of worn parts.

POWER BOILERS

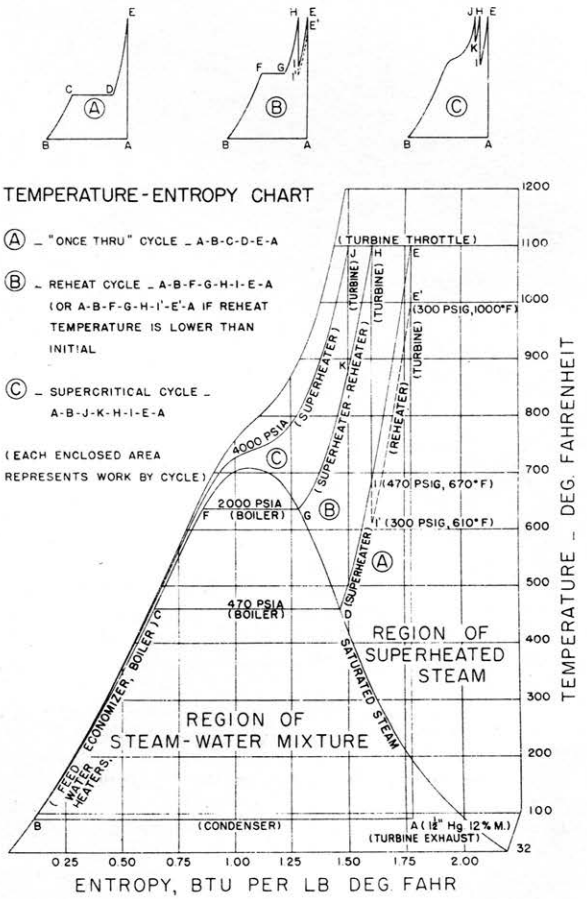
As mentioned in the Introduction, the economics of power generation have justified the use of successively higher steam pressures and temperatures, as well as larger units. System growth and interconnection permits these larger units; a 200 megawatt unit may be a smaller proportion of a system capability today than one half that size ten years ago, and require no more operating labor.



Unit size for electric power generation.

That the higher pressure steam cycles require higher temperatures can be demonstrated and the relation between them understood by a study of the temperature - entropy diagram. An initial steam temperature higher than that required to accommodate the maximum tolerable moisture fraction at the turbine exhaust needlessly increases (proportionately) the condenser loss. Accepting the usual limit of wet-end condition as 10-12% moisture, an isentropic line (vertically upward) soon enters the superheated area. The expansion is not exactly isentropic, but the demonstration applies. As pressure increases, the required initial temperature rises rapidly. In practice, however, a temperature of 1050° corresponds to an initial pressure of about 1200 psia.

Metallurgical considerations, and to a lesser degree the temperature of the combustion products, limit steam temperature. Tubing now available sets this limit at about 1100 - 1200°F. Therefore, the higher pressures cannot advantageously be used without reheating the steam. Present practice is to expand the steam thru the high pressure stages of the turbine to a pressure of about 400 - 500 psi, at which point it is still in the superheated region,

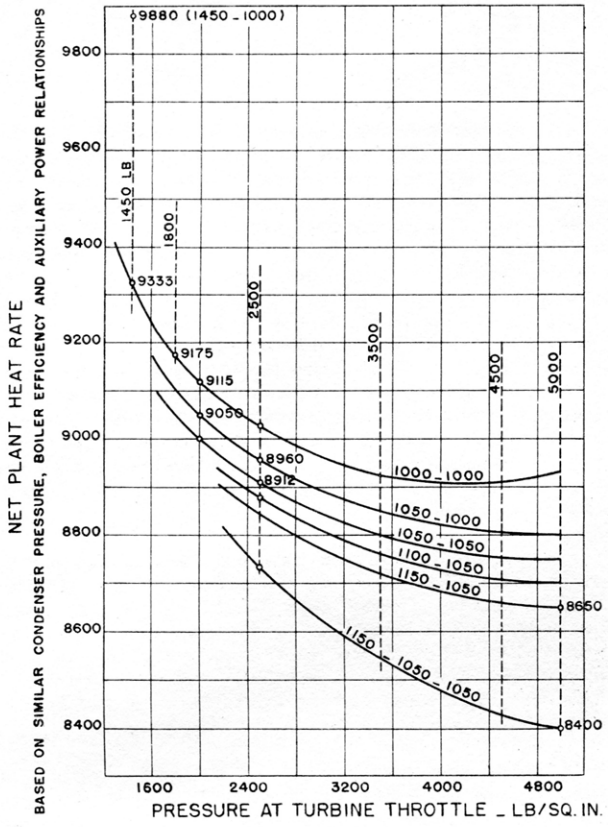


Temperature - Entropy Diagram showing theoretical temperature-pressure relationship.

return it to the steam generating unit for reheating to about the same as the initial temperature, then to the intermediate stage of the turbine.

Theoretically, initial steam temperature could be minimized by reheating in several steps in a manner somewhat analogous to turbine bleeding for regenerative feed heating, but friction losses tend to reduce the advantage, and cost and complication of boiler, turbine, and connecting piping strongly oppose it. Reheating by circulating some fluid from the steam generator to a heat exchanger at the turbine is a possibility. Studies have been made of reheating in several stages, but practice is limited to one, except in the supercritical cycle.

Use of these more efficient steam cycles has had an important effect on boiler design, quite aside from considerations relating to circulation. Low pressure boilers with small superheaters absorb much of the heat in the combustion products by means of convection surface consisting of a bank of tubes. Economics may or may not justify second-

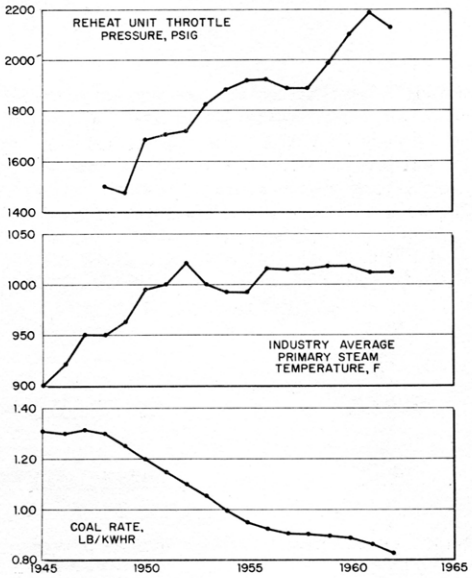


Study of net overall heat rates corresponding to some steam temperature and pressure combinations

ary heat absorbing surface (economizer and/or air heater). At higher pressures the increase in saturation temperature reduces the temperature difference between water/steam and combustion gas, and higher temperatures, particularly with reheat, increase the amount of heat to be absorbed by the superheater(s) and the temperature at which it must be transferred. Thus the metamorphosis in steam generator design has seen a reduction in convection evaporative surface to the point of elimination, and an increase in superheater and secondary heat absorbing surfaces, so that a modern power boiler consists of furnace, superheaters, economizer and air heater. The latent heat of vaporization is added to the water in the furnace wall tubes.

The use of improved cycles and more efficient boiler design have steadily reduced Btu/kw hr. from perhaps 25,000 to about 9,000 in the past twenty-five to thirty years (these are not national averages) in the subcritical region. A projected supercritical installation with two stage reheat has a calculated heat rate of about 8000 Btu/kw hr.

While these improvements involve greatly increased capital expenditures, they have not been made at the expense of safety and reliability. Indeed, the reverse is true. Whereas "spare" boilers were the rule some years ago, improved design and operating practices, largely better materials, the elimination of furnace brickwork, and more careful water conditioning, have made boilers more "reliable" from the standpoint of unscheduled outages



Average steam conditions and heat rates for electric power generation.

than the prime movers they serve. Insurance inspections usually require annual shut-downs, but several large boilers have operated continuously for fifteen months or more.

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A discussion of trends suggests a projection into the future. It appears that there is little leeway at the high pressure end of the cycle except as improved materials may permit higher temperatures. Condenser pressure is determined by available cooling water temperature and cannot be changed appreciably. The large heat loss occurs in the condenser.

This suggests a binary fluid cycle which might be considered as simulating a multiple effect evaporator, but no practical fluid has been found.

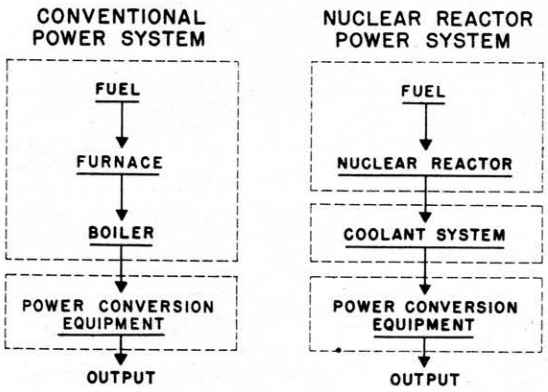
Another possibility which has been proposed is a combination gas and steam cycle, in which the combustion products, under pressure, pass from the furnace and superheater to a gas turbine, then to secondary heat absorbing surfaces. The combination studied indicates a possible reduction of approximately 7% in the heat rate. Application would be limited to clean (no ash) fuels.

Of course efficiency can be improved by further reduction of exit gas temperature, now limited by corrosion resulting from condensation of sulfur compounds, as means of preventing corrosion are developed.

While the future will not see as much improvement in overall efficiency as has the past, equipment arrangements will change and unit size will increase. The trend may tend to emphasize reduction in total equipment cost rather than the cost of fuel.

NUCLEAR POWER

Since all commercial power reactors in the U.S. generate electricity by means of steam, the subject of Nuclear Power is appropriately included here. In effect fissionable uranium is a new kind of fuel, altho the liberation of heat does not involve combustion as in the case of our fossil fuels.



Diagrammatic comparison of conventional and nuclear power systems.

Depletion of world resources of coal, oil, and gas and the increasing inaccessibility of supplies under ground continuously increase the cost of these fuels. Greatly improved and highly ingenious production methods have not entirely offset this trend. Coal quality deteriorates, particularly as to ash quantity and fusion temperature, as the better seams approach exhaustion; compensation by better cleaning is costly. In the survey of substitute energy sources, atomic fission seems most promising.

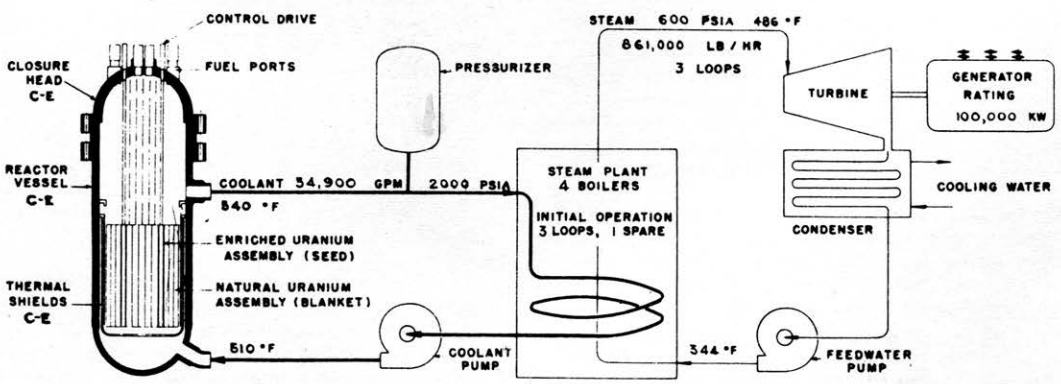
Commercial incentive to the development of nuclear power is naturally greatest in the localities where conventional fuels are most expensive. The cost of conventional fuels is a matter not only of availability but also largely of transportation; in transportation the atomic fuel has the enormous advantage that it is practically weightless and does not require frequent delivery.

The uranium isotopes U-233 and U-235 and plutonium PU-239 are fissionable. When struck by a neutron, the U-235 atom will break down into other elements with the release of 200 million electron volts of energy per atom or 3.2 X 10-4 ergs. This means that 3.1×10^{10} fissions/sec will produce 1 watt, and that the complete fission of one gram of uranium will produce about 25,000 Kw-hr of energy. Thus from the standpoint of heat release, U-235 is 2,600,000 times as powerful as an equal weight of coal, combustion air not included. The comparison is farfetched since nuclear fuel elements contain non-fissionable material, and only about one or two per cent of the fissionable material is available before the fuel is poisoned by fission products to the extent that the reaction no longer proceeds.

Uranium U-238 and thorium Th-232 are fertile materials which may be transmuted to the fissionable material U-239 and U-233 by neutron bombardment. The economy of nuclear power reactors generally depends on this transmutation in their operation; i.e., such reactors breed more fuel in this way and thus reduce costs through the sale or use of the fissionable products they produce.

While the occurrence of U-238 is quite wide (usually as an oxide of uranium) its dispersion in the ores makes concentration difficult. A small amount of U-235 is associated with U-238, and refinement to a fuel concentration provides the "enriched" uranium used in the U.S. reactors. It is estimated that the world reserve of fission fuels is more than twenty times that of fossil fuels.

The cost of energy as heat or electricity is made up of several factors, chiefly fuel, labor, and investment charges. For an equivalent amount of available energy, nuclear fuel costs very much less than coal. It does not appear that the operating labor cost of a nuclear power plant will be significantly less than that of a conventional plant, and maintenance may be much greater, depending on the type of reactor installed. Fuel reprocessing and disposal, and repairs to radio-active parts, pose very difficult problems from a safety standpoint requiring intricate, thus expensive, handling procedures.



Schematic arrangement of PWR nuclear power system.

Many types of reactors have been devised; each has advantages and disadvantages for given applications. One differentiation is in the fluid used to cool the reactor and conduct the heat to the steam generator. The most successful commercial power reactor in this country - that on the submarine Nautilus - uses light water under pressure as a coolant. Another design uses liquid metal. The British Calder Hall plant uses CO_2, with the rather large dimensions imposed by the lower heat transfer rate with gas.

The utilization of nuclear energy in the generation of electric power is not efficient. Not only does the fuel not burn out cleanly, the characteristics of the coolants and the materials of which the reactors are constructed limit the temperature at which heat can be transferred to the steam. A practical pressurized water reactor is limited to the generation of steam at about 485°F, or a pressure at saturation of about 600 psig. Liquid sodium raises this limit, but with increased hazard if leakage should occur. The steam cycle is, therefore, inefficient as compared to conventional plants and imposes the need for larger turbines at lower pressure, and greater amounts of condensing water.

A large part of the initial cost results from the danger to personnel from radiation. Construction must be kept scrupulously clean to exclude particles which might become radio-active and be carried thru the system; it must be tight to a requirement far greater than in conventional plants to avoid the escape of radio-active materials. The reactor and appurtenant parts must be enclosed in a pressure tight containing vessel and operated by remote control. Finally, all radio-active parts must be heavily shielded.

These requirements greatly reduce the applicability of nuclear power systems for propulsion of anything smaller than a ship. The fuel is light but shielding may be prohibitively heavy, and the damage from catastrophic failure could be tremendous. Indeed, adequate insurance protection even for stationary plants is a serious obstacle to nuclear power development.

Principal obstacle to the adoption of nuclear power is investment cost, which is several times that of conventional plants. The economics of nuclear reactors for power production is without doubt one of the greatest unknowns in the field today. Reactor cost is a favorite weapon used politically and otherwise in opposition to private development of commercial nuclear power. However, since all reactors to date have been somewhat experimental, an honest appraisal of the situation requires recognition of the fact that an economic comparison of such experimental nuclear fueled power plants to conventionally fueled plants is invalid.

There are serious chemical problems, material problems, metallurgical (involving not only initial suitability but deterioration from radiation), and those involving mechanical design. Maintenance problems are at this time largely a matter of conjecture. It appears, none the less, that nuclear power is the important source of controlled energy in the future.

Commercial development can be expected first in such countries as England and France which already suffer a comparative shortage of conventional fuels, and - as emphasized by the Suez Canal crisis - are dependent on outside supply. Meanwhile development in this country is proceeding, but without the impetus, as yet, of real economic necessity in the field of electric power generation.

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